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BEFORE THE ARIZONA CORPORATION COMMISSION

LEA MÁRQUEZ PETERSON
Chairwoman
SANDRA D. KENNEDY
Commissioner
JUSTIN OLSON
Commissioner
ANNA TOVAR
Commissioner
JIM O'CONNOR
Commissioner

Arizona Corporation Commission
DOCKETED
MAR 02 2022
DOCKETED BY
LC

IN THE MATTER OF RESOURCE PLANNING AND PROCUREMENT IN 2019, 2020 AND 2021.	DOCKET NO. E-00000V-19-0034 Decision No. 78499 ORDER

Open Meeting
December 15 and 16, 2021
Phoenix, Arizona

STAFF ASSESSMENT OF 2020 INTEGRATED RESOURCE PLANS

BY THE COMMISSION:

FINDINGS OF FACT

Background

1. The Resource Planning and Procurement Rules ("IRP Rules") were adopted by the Arizona Corporation Commission ("ACC" or "Commission") on February 3, 1989, and amended by final rulemaking, effective December 20, 2010. The IRP Rules are found in the Arizona Administrative Code ("A.A.C.") at Title 14, Chapter 2, Article 7 "Resource Planning and Procurement", et seq. [1]

2. The IRP Rules require that 15-year Integrated Resource Plans ("IRP" or "IRPs") be prepared and submitted by "Load Serving Entities" ("LSEs") to the Commission in each evenly numbered year on April 1.

3. Attached to the docketed copy of this Decision is the Report ("Staff Report"), pursuant to A.A.C. R14-2-704(A), that contains Commission Utilities Division Staff's ("Staff") analysis and conclusions regarding its statewide review and assessments of the LSEs filings made under A.A.C. R14-2-703(C), (D), (E), (F), and (H) (the IRPs). In addition, Staff executed a contract

1 https://apps.azsos.gov/public_services/Title_14/14-02.pdf

with Ascend Analytics ("Ascend") and Verdant Associates (combined "the Ascend team") to serve as a third-party analyst to review the 2020 IRPs filed by Arizona Public Service Company ("APS"), Tucson Electric Power Company ("TEP"), and UNS Electric, Inc. ("UNSE"). The Ascend team's report was filed on August 11, 2021, in the docket. Subsequent to the filing, the Ascend team identified the need to make corrections to its report. As a result, a corrected copy of the Ascend team's independent review of the IRPs was filed on August 13, 2021.[2]

Staff Analyses and Recommendations

4. Staff reviewed the 2020 IRPs, Commissioner comments, stakeholder comments and recommendations, the Ascend team's analysis and recommendations, and other relevant filings made in the docket.

5. Based on its review, Staff concludes:

1. APS has a stated goal of delivering 100 percent clean, carbon-free, and affordable electricity to customers by 2050. In order to achieve the 2050 goal, APS plans to have a resource energy mix which leads to 65 percent clean energy with 45 percent of customers' electricity needs served by renewable energy by 2030. APS has made a commitment to end the use of coal-fired generation by 2031. In its IRP, APS presents three portfolios which are: The Bridge, Shift, and Accelerate Portfolios. The portfolios include approximately 8,000, 9,500, and 12,000 megawatts ("MW") of additional renewable capacity, respectively.

2. APS did not select a Preferred Portfolio, as required by R14-2-703(F)(1), and states that its Five-Year Action Plan is identical for all three portfolios. APS's 2020 – 2024 Action Plan includes 2,894 MW of the following resource additions: 575 MW demand side management, 193 MW of demand response, 408 MW of distributed energy, 962 MW of renewable energy, 750 MW of energy storage, and a 6 MW microgrid. After the Five-Year Action Plan period, each portfolio's resource additions differ dramatically.

3. In TEP's 2020 IRP, TEP states that "TEP's long-term strategy is now focused on completing the transition to 100 percent clean energy." TEP developed and presented a total of 15 wide ranging portfolios. TEP's Preferred Portfolio plans to reduce its reliance on coal generation and anticipates adding 450 MW of renewable capacity by 2021 to increase the total renewable energy portfolio to over 1,000 MW, or approximately 28 percent of TEP's energy portfolio, as well as increasing investment in energy storage. TEP's Preferred Portfolio will significantly increase its solar and wind power use as well as battery

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2 The Ascend team produced an addendum, filed on September 21, 2021 in the docket: https://docket.images.azcc.gov/E000015791.pdf?i=1636386156053

storage to serve approximately 70 percent of its retail load by 2035 with renewable resources and achieve 80 percent reduction in carbon dioxide from 2005 levels.

4. TEP's Five-Year Action plan states it will complete the first phase of coal plant retirements when San Juan Unit 1 closes in June 2022. With that retirement, TEP will have retired 41 percent of its coal capacity since 2015. TEP will complete the build-out of planned solar and wind projects currently under contract or construction, which will double TEP's renewable energy output. TEP states it will initiate discussions with stakeholders regarding impacts due to the retirement of Springerville Generating Station Units 1 and 2. Furthermore, TEP will continue to implement cost-effective Energy Efficiency ("EE") programs consistent with historical levels targeting 1.5 percent incremental energy savings over the prior year's retail load in each year through 2024. In addition, TEP is committed to procuring future resources through All-Source Requests for Proposal ("ASRFP") based on specific, identified system needs. Finally, TEP states it will continue preparations for joining the California Independent System Operator's ("CAISO") Western Energy Imbalance Market ("EIM") in April 2022.

5. UNSE states its 2020 IRP is designed to gradually divert the capacity mix from utilizing purchased power to predominantly utilizing self-reliant generation. Furthermore, UNSE states that it is committed to reaching a goal of supplying 50 percent of its energy to retail customers from renewable resources by 2035, while also remaining committed to reducing its carbon emissions. UNSE developed four resource portfolios in its IRP. UNSE's Preferred Portfolio has an energy mix consisting of increasing energy efficiency, a relatively consistent level of market purchases, increasing renewable energy, and consistent natural gas utilization, with a slight decrease in 2028. UNSE states that its Preferred Portfolio represents the lowest overall cost while still allowing them to reach the 50 percent goal by 2035. In addition, UNSE states this portfolio achieves the highest energy efficiency savings out of the evaluated portfolios.

6. UNSE's Five-Year Action Plan states it will continue to implement cost-effective EE programs consistent with historical levels targeting 1.5 percent incremental energy savings over the prior year's retail load in each year through 2024. UNSE will continue to procure market-based resources to meet its short-term capacity needs through 2024. In the interim, UNSE will explore other options through its future ASRFPs to acquire alternative resources if they are proven to be more cost-effective. UNSE states it is committed to procuring future resources through ASRFPs based on specific, identified system needs. UNSE anticipates issuing an ASRFP in 2022 or 2023. UNSE is conducting studies relating to the costs and benefits of actively participating in the CAISO Western EIM.

7. The 2020 Integrated Resource Plans produced by APS, TEP and UNSE are reasonable and in the public interest, based upon the information available to

Staff at the time this report was prepared, and the requirements set forth in A.A.C. R14-2-703(C), (D), (E), (F), (H) and A.A.C. R14-2-704(B).

8. Arizona Electric Power Cooperative, Inc. ("AEPCO") has satisfied the requirements of Decision No. 73884. AEPCO has continued to participate in the IRP process by filing the information, data, criteria, and studies it has used in its 15-year planning scenarios, without the necessity of having its IRP acknowledged by the Commission.

9. The LSEs have complied with Decision No. 76632 with the following exceptions:

   a. TEP and UNSE did not include a tabular representation that provides a breakdown by capacity and energy mix contributions for each portfolio that was analyzed, similar to Table ES-2 on Page 13 of APS's 2017 IRP.

   b. APS and TEP failed to discuss the costs and benefits of natural gas storage. TEP and UNSE also failed to discuss the risks of a lack of market area natural gas storage in Arizona and only briefly describe what would be required to advance efforts to develop natural gas storage without describing the status of any efforts to develop storage or lack thereof.

   c. APS provided discussion of various storage technologies and chemistries in its 2020 IRP in the titled "Energy Storage" section but provided no analysis of anticipated future energy storage cost declines of these technologies.

   d. Staff has requested that APS, TEP, and UNSE identify where this information can be found. Although this information is omitted from the 2020 IRPs, Staff believes the IRPs are reasonable and in the public interest.

10. Each 2020 IRP (except AEPCO's) meets the requirements of the Annual Renewable Energy Requirement ("ARER"), the Distributed Renewable Energy Requirement, and the Energy Efficiency Standard.

11. The LSE load forecasts and IRPs were developed before the onset of the COVID-19 pandemic. As a result, the economic impacts of the pandemic, and the associated impact on future electric demand, could not have been adequately considered. It is unclear what changes to the Action Plans, if any, would be required based on these factors.

12. APS, TEP, and UNSE have included a reasonable range of technologies and associated costs in the 2020 IRPs.

13. The price of natural gas has both short- and long-term impacts on an LSE's resource procurement decisions. Given the expressed desire by APS, TEP, and UNSE, in the 2020 IRPs, to achieve significant carbon emissions reductions, the impact of a wide range of natural gas prices on resource procurement decisions needs to be thoroughly discussed in the IRP.

14. Forecasting the future cost of carbon dioxide will continue to play an important role in understanding the costs and benefits of the various portfolios presented by each LSE in its IRP.

15. Participation in regional markets, such as the EIM, may provide benefits to ratepayers and result in more efficient resource procurement. Therefore, APS, TEP, and UNSE should improve future IRPs by analyzing to what extent regional market participation affects near- and long-term resource procurement actions.

16. The TEP and UNSE IRPs lack sufficient supporting information required by A.A.C. R14-2-703(D)(1)(a), R14-2-703(D)(14), R14-2-703(D)(17), R14-2-703(E), and R14-2-703(F)(3) (see Section V(G)(5) of the Staff Report for further discussion).

17. Existing generation resources that emit carbon will have to be retired at some point for the LSEs to achieve the goals established in the 2020 IRPs. Therefore, the inclusion of a robust retirement analysis in future IRPs is paramount given these commitments. A robust retirement analysis should identify optimal resource retirement dates and quantify cost savings to ratepayers. Several stakeholders and Commissioners expressed questions and/or concerns with the identification of "must run" resources and the retirement dates presented by each LSE for various resources. The facts and circumstances around the operation of a utility's generation resources are not self-evident and should be accompanied by supporting analysis so that the Commission and stakeholders understand the basis of an LSE's decision making.

18. There are many paths that can be taken to achieve significant carbon emission reductions. The analysis of a wide range of portfolios helps Commissioners and stakeholders understand the costs and benefits of achieving these reductions. In addition to understanding the costs and benefits, analyzing a wide range of portfolios ensures the optimal or least cost portfolio could be selected so that the goals of the LSE can be satisfied.

19. The LSEs state that clean and renewable energy technologies are continuing to decline in cost and that the adoption and use of these technologies can help lower costs to ratepayers. The costs and benefits of adopting a 100 percent reduction in emissions will need to be continuously evaluated and presented in future IRP proceedings.

20. In future IRPs, the issue of resource adequacy should be discussed more thoroughly, and actions taken to address the issue of resource adequacy should be fully supported. On December 18, 2020, the Western Electricity Coordinating Council ("WECC") released a report titled "The Western Assessment of Resource Adequacy Report" in which, WECC found that traditional methods of resource planning will not be adequate in the future due to the increasing variability on the system and if high levels of resource adequacy are to be preserved, resource planning methods and practices must adapt. Therefore, LSEs should analyze the resource adequacy implications of each of their scenarios, present the conclusions of this analysis and explanations of the methods used, and describe their efforts to adapt their resource adequacy analysis methods and practices to address increasing variability on the system.

21. Given the commitments made by APS, TEP, and UNSE to reduce emissions, it would be beneficial for each LSE to further explore broad environmental costs and benefits of the portfolios presented in each IRP. R14-2-704(B) requires the Commission consider the environmental impacts of resource choices and alternatives, the degree to which the LSE considered all relevant resources, risk, and uncertainties, and the degree to which the LSE's IRP is in the best interest of its customers in determining the public interest (R14-2-704(B)(7)-(9)).

22. R14-2-703(D)(17) requires that the IRPs address the adverse environmental impacts of power production. Therefore, APS, TEP, and UNSE should present information about the broader environmental impacts (e.g., societal costs of carbon emissions and water consumption associated with their resource choices) in their scenario analyses and IRPs, so the Commission and stakeholders have the benefit of this information, as supported under the IRP Rules.

23. A.A.C. R14-2-703 requires that the LSEs file the IRPs by April 1 of each even year. The filing requirements for the current IRP cycle have been established by Decision No. 76632 which also waived the relevant filing requirements in the IRP Rules. Furthermore, Decision No. 77696 ultimately required the 2020 IRPs be filed by August 26, 2020. Given these modifications to the filing requirements, the LSEs are unable to file the next IRPs, while utilizing a three-year development process, by April 1, 2022, which is the filing requirement for the next IRPs specified by A.A.C. R14-2-703.

24. Consistent with this IRP cycle and Commission Decision No. 76632, a three-year process should be utilized for the development of the next IRPs.

25. Ascend notes that, "overall, the discussion of gas storage is brief and does not provide a detailed analysis of the arguments for or against developing natural gas storage in Arizona. Future IRPs should provide additional in-depth analysis related to system reliability and the risks/consequences of pipeline distribution." Furthermore, the Ascend team states, the recent "situation on

the Texas grid in February 2021 highlighted the need for utilities to investigate the interconnected risks of the gas system failing to deliver adequate supply to power plants during periods of extreme weather. While Arizona is unlikely to experience the same cold weather conditions [as Texas did in February 2021], we recommend APS include in their next IRP an analysis of power system resiliency to extreme weather, including correlated risks to both the power and gas systems. Gas storage could potentially provide a hedge against natural gas supply interruptions and price shocks that would ultimately benefit APS customers."

26. Ascend notes, "policy and economic trends portend a decline in the demand for natural gas. As renewables generate more of the system energy, gas units' capacity factors will decline. At the same time, air source heat pumps are expected to reduce residential and commercial end use of natural gas. The implications of winding down the gas system as well as replacing natural gas with hydrogen and/or renewable natural gas should be studied by APS in the next IRP as part of the broader push for decarbonization." TEP and UNSE should also study these implications in future IRPs.

6. Staff recommends that:

1. APS, TEP, and UNSE include in future IRPs a comprehensive analysis of power system resiliency to extreme weather, including correlated risks to both the power and gas systems.

2. APS, TEP, and UNSE file, as a compliance item in this docket, updated Five-Year Action Plans that describe whether near-term resource selections have been impacted due to changes in the LSE's load forecast attributable to the COVID-19 pandemic within 90 days of the Commission's Decision in this matter.

3. APS, TEP, and UNSE include in future IRPs a dedicated section that explicitly discusses the LSE's natural gas price assumptions, the resulting impact of those assumptions on the LSE's short- and long-term resource procurement decisions, and the implications of declining natural gas usage as the LSE shift resource mixes to achieve emissions reductions.

4. APS, TEP, and UNSE closely monitor federal legislation, and any other relevant legislation, related to a carbon tax and include in future IRPs a relevant discussion of the impacts of such legislation on the development of the IRP.

5. APS, TEP, and UNSE include in future IRPs a discussion of participation in regional markets and the effects of that participation on near- and long-term resource procurement actions.

6. TEP and UNSE include sufficient information in future IRPs regarding environmental considerations, as required by the IRP Rules.

7. The Commission order APS, TEP, and UNSE to include robust retirement analyses in future IRPs. Future IRPs should include a dedicated, comprehensive, analysis describing how the LSE evaluated the operations of its current resources, how retirement dates were selected, and why, and what the economic impact to ratepayers will be.

8. The Commission order APS, TEP, and UNSE to include in future IRPs an analysis of, at minimum, 10 resource portfolios that are designed to evaluate the range of resource procurement actions, and their respective costs and benefits, that can be taken to achieve the emissions reductions goals specified by each in its 2020 IRP. The analysis and presentation of these resource portfolios should be used to support APS, TEP, and UNSE's desire to achieve significant emissions reductions. In addition to the 10 resource portfolios Staff recommends, it is reasonable and in the public interest to require APS, TEP, and UNSE to include in future IRPs an analysis of a technology agnostic portfolio, which is the least-cost method of safely and reliably meeting customers' energy needs without regard for their emissions reduction goals or any renewable or carbon emissions standards.

9. The Commission order APS, TEP, and UNSE to include in future IRPs a comprehensive analysis that presents the costs and benefits of their emissions reduction commitments, compared to an approach absent these commitments, to their ratepayers.

10. APS, TEP, and UNSE include in future IRPs, a comprehensive discussion regarding how the LSE's methods for addressing resource adequacy are being adapted to address concerns with increasing variability on the bulk electric system.

11. The Commission adopt the Ascend team's recommendations as detailed on pages 10 and 11 of its Redacted Revised Report dated August 12, 2021.

12. The Commission waive the filing requirements contained in A.A.C. R14-2-703 which require the LSEs to file the next IRPs by April 1, 2022.

13. The Commission require the next IRPs to be filed by August 1, 2023.

14. The Commission order Staff to file in this docket, for the Commission's consideration, a recommended development timeline for the next IRPs within 90 days of the Commission's decision in this matter.

15. The Commission find that the 2020 IRPs are reasonable and in the public interest.

16. The Commission acknowledge the 2020 IRPs submitted by APS, TEP, and UNSE.

17. The Commission find that the information filed by AEPCO satisfies the requirements established in Decision Nos. 73884 and 75068.

Strategen Analyses and Recommendations

7. However, the independent capacity expansion analysis conducted by Strategen Consulting on TEP's integrated resource plan identified the potential to reduce the net present value of TEP's revenue requirement if TEP implements both the economic cycling of coal and implements greater energy efficiency by 2030 using a 2010 baseline. In order to maximize customer savings and benefits, we therefore agree that increasing demand side resource capacity should be instituted.

Strategen Analyses and Recommendations

8. However, the independent capacity expansion analysis conducted by Strategen Consulting on APS's integrated resource plan identified the potential to reduce the net present value of APS's revenue requirement if APS implements both the economic cycling of coal and implements greater energy efficiency by 2030 using a 2010 baseline. In order to maximize customers savings and benefits, we therefore agree that increasing demand side resource capacity should be instituted.

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9. The Commission shall consider future rate base treatment of Demand-Side Resources ("DSRs")[3] in the next rate cases of Arizona Public Service Company, Tucson Electric Power, and UNS Electric, Inc.

CONCLUSIONS OF LAW

1. Arizona Public Service Company, Tucson Electric Power Company, UNS Electric, Inc., and Arizona Electric Power Cooperative, Inc. are Arizona public service corporations within the meaning of Article XV, Section 2, of the Arizona Constitution.

2. The Commission has jurisdiction over Arizona Public Service Company, Tucson Electric Power Company, UNS Electric, Inc., Arizona Electric Power Cooperative, Inc., and over the matters raised herein.

3. The findings, conclusions and recommendations contained in Staff's Memorandum are reasonable and in the public interest, as modified herein.

ORDER

IT IS THEREFORE ORDERED that Arizona Public Service Company, Tucson Electric Power Company, and UNS Electric, Inc. include in future Integrated Resource Plans a

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3 "Demand Side Resources" means any DSM Measure, DSM Program, Demand Response-based mechanism, Energy Efficiency-based mechanism, or Load Management-based mechanism.

"DSM Measure" means any material device, technology, educational program pricing option practice, or facility alteration designed to result in reduced peak demand, increased Energy Efficiency, or shifting of energy consumption to off-peak periods.

"DSM Program" means a Utility program provided as part of a single offering to its customers and designed to implement:

a. One or more DSM Measures,
b. Demand Response, or
c. Or Energy Efficiency

"Demand Response" means modification of customers energy consumption patterns, affecting the timing or quantity of customer demand and usage achieved through intentional actions taken by a utility or the customer.

"Energy Efficiency" means the production or delivery of an equivalent level and quality of end use electric or gas service using less energy, or the conservation of energy by a customer.

"Load Management" means actions taken or sponsored by a utility to reduce peak demands or improve system operating efficiency such as:

a. Utilizing an energy storage system,
b. Educational campaigns to encourage customers to shift loads, or
c. Direct control by the utility of customer demands through interruptible service

comprehensive analysis of power system resiliency to extreme weather, including correlated risks to both the power and gas systems.

IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson Electric Power Company, and UNS Electric, Inc. shall file, as a compliance item in this docket, updated Five-Year Action Plans that describe whether near-term resource selections have been impacted due to changes in the load-serving entity's load forecast attributable to the COVID-19 pandemic within 90 days of the Commission's Decision in this matter.

IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson Electric Power Company, and UNS Electric, Inc. include in future Integrated Resource Plans a dedicated section that explicitly discusses the load serving entities' natural gas price assumptions, the resulting impact of those assumptions on the load-serving entity's short- and long-term resource procurement decisions, and the implications of declining natural gas usage as the load-serving entities shift resource mixes to achieve emissions reductions.

IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson Electric Power Company, and UNS Electric, Inc. shall closely monitor federal legislation, and any other relevant legislation, related to a carbon tax and include in future Integrated Resource Plans a relevant discussion of the impacts of such legislation on the development of the Integrated Resource Plan.

IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson Electric Power Company, and UNS Electric, Inc. shall include in future Integrated Resource Plans a discussion of participation in regional markets and the effects of that participation on near- and long-term resource procurement actions.

IT IS FURTHER ORDERED by June 1, 2023, Arizona Public Service Company, Tucson Electric Power Company, and UNS Electric, Inc. shall each file in the 2023 Resource Planning and Procurement docket a Market Report on the status of their engagement in regional market development forums including, but not limited to, the Energy Imbalance Market, the Western Market Exploratory Group, the Enhanced Day Ahead Market of the California Independent System Operator, and the Western Resource Adequacy Program. The Market Report shall discuss their participation and intentions for further participation including cost savings and other benefits, barriers and concerns related to governance of western market proposals, transmission planning, coordination, open-access tariff consolidation, cost allocation and utilization arrangements, planning for resource adequacy and shall identify information the Commission needs to aide in future enabling decision-making. The Market Report shall include their anticipated development steps, including timelines and decision points from all parties leading to, among other things, obtaining lower costs for customers through greater cooperation and coordination in the Western Interconnection. Arizona Public Service Company, Tucson Electric Power Company, and UNS Electric, Inc. shall host a workshop on the content and findings of their Market Reports for stakeholders as part of its Integrated Resource Plan process.

IT IS FURTHER ORDERED that Tucson Electric Power Company and UNS Electric, Inc. shall include sufficient information in future Integrated Resource Plans regarding environmental considerations, as required by the Resource Planning and Procurement Rules.

IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson Electric Power Company, and UNS Electric, Inc. shall include robust retirement analyses in future Integrated Resource Plans including specific estimated retirement dates for each resource. Future Integrated Resource Plans should include a dedicated, comprehensive, analysis describing how the load-serving entity evaluated the operations of its current resources, how retirement dates were selected, and why, and what the economic impact to ratepayers will be.

IT IS FURTHER ORDERED in its next resource planning process, Tucson Electric Power Company shall file a comprehensive early retirement analysis for Springerville Generating Station Units 1 and 2 and of its stake in Four Corners Power Plant, and Arizona Public Service Company for its stake in Four Corners Power Plant. In the case of both facilities, retirement dates in 2024, 2025, 2026, 2027, 2028, 2029, 2030, and 2031 shall be considered ("Early Retirement Analysis"). This analysis shall include an evaluation of the economic costs and benefits to customers from the retirement and possible necessary replacement of energy and capacity and impacts to electric reliability. Tucson Electric Power Company and Arizona Public Service Company shall consult with Staff on at least a quarterly basis in order for Staff to ensure the Early Retirement Analysis is not unfairly favoring or disfavoring any technology, skewing its analysis in such a way to overweight or under-weight any particular resource, using an industry-accepted capacity valuation for battery storage, incorporating any changes in federal tax credit policy, and using reasonable assumptions for future Springerville Generating Station and Four Corners Power Plant capacity factors, outage rates, operations and maintenance costs, fuel costs, carbon taxes, capital expenditures, reliability/technology risks, and operating performance given recent trends in performance for each generator. Staff may consider any other factor considered relevant to ensure a fair Early Retirement Analysis occurs. Arizona Public Service Company shall not include in its Early Retirement Analysis any additional coal contract and operating agreement termination liability or restrictions beyond those the company was subject to on March 3, 2021.

IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson Electric Power Company, and UNS Electric, Inc. shall include in future Integrated Resource Plans an analysis of, at minimum, 10 resource portfolios that are designed to evaluate the range of resource procurement actions, and their respective costs and benefits, that can be taken to achieve the emissions reductions goals specified by each in its 2020 Integrated Resource Plan. The analysis and presentation of these resource portfolios should be used to support Arizona Public Service Company's, Tucson Electric Power Company's, and UNS Electric, Inc.'s desire to achieve significant emissions reductions.

IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson Electric Power Company, and UNS Electric, Inc. shall include in future Integrated Resource Plans an analysis of a technology agnostic resource portfolio, which is the least-cost method of safely and reliably meeting customers' energy needs without regard for their emissions reduction goals or any renewable or carbon emissions standards.

IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson Electric Power Company, and UNS Electric, Inc. shall in future Integrated Resource Plans study and report upon the value of distribution grid-connected resources as compared to transmission-connected, to determine the optimal mix of renewable energy and energy storage interconnected to distribution versus resources interconnected to transmission. Factors to consider include constraints in the transmission grid, the cost and process of siting and building new transmission, and the benefits of distribution connected resources such as reduced line loss and resiliency.

IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson Electric Power Company, and UNS Electric, Inc. shall include in future Integrated Resource Plans a comprehensive analysis that presents the costs and benefits of their emissions reduction commitments, compared to an approach absent these commitments, to their ratepayers.

IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson Electric Power Company, and UNS Electric, Inc. shall include in future Integrated Resource Plans, a comprehensive discussion regarding how the load serving entities' methods for addressing resource adequacy are being adapted to address concerns with increasing variability on the bulk electric system.

IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson Electric Power Company, and UNS Electric, Inc. shall in future Integrated Resource Plans negotiate a project-based licensing fee that permits up to 12 Resource Planning Advisory Council members and Staff the ability to perform their own modeling runs in the same software package as these load serving entities, and to provide all necessary data and support to fully utilize the models. The load serving entities shall absorb the cost of the licensing fees.

IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson Electric Power Company, and UNS Electric, Inc. shall in future Integrated Resource plans include one or more portfolios which eliminate coal unit must-run designations.

IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson Electric Power Company, and UNS Electric, Inc. shall in future Integrated Resource Plans include one or more portfolios which remove modeling restrictions that limit the amount of energy efficiency that can be selected as a resource option.

IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson Electric Power Company, and UNS Electric, Inc. shall in future Integrated Resource Plans include one or more portfolios which remove modeling restrictions on the economic cycling and economic retirement of coal units.

IT IS FURTHER ORDERED that Arizona Public Service Company shall file quarterly reports on the accuracy of its load forecast, including weather-normalized values for energy and peak load.

IT IS FURTHER ORDERED that Arizona Public Service Company shall in future Integrated Resource Plans include a full accounting of the sources and costs of the hydrogen fuel and any associated capital expenditures to produce that fuel.

IT IS FURTHER ORDERED that Arizona Public Service Company shall in future Integrated Resource Plans include the extension of key tax credits (i.e., the Investment Tax Credit and the Production Tax Credit) and its plan to run one of the Four Corners units seasonally.

IT IS FURTHER ORDERED that Arizona Public Service Company shall in future Integrated Resource Plans include information on how each portfolio performs in terms of total cumulative emissions reductions in addition to annual emissions numbers.

IT IS FURTHER ORDERED that Arizona Public Service Company shall in future Integrated Resource Plans include one or more portfolios which achieve an annual minimum of 1.5 percent energy savings as a percent of retail sales from a broad portfolio of energy efficiency measures (consistent with 15 percent cumulative savings over 10 years).

IT IS FURTHER ORDERED that Tucson Electric Power shall in future Integrated Resource Plans include one or more portfolios which achieve at least 40 percent cumulative energy savings by 2030 from a broad portfolio of energy efficiency measures and using a 2010 baseline.

IT IS FURTHER ORDERED that Tucson Electric Power Company shall in future Integrated Resource Plans include a portfolio that eliminates coal unit must-run designations.

IT IS FURTHER ORDERED that Tucson Electric Power Company shall in future Integrated Resource Plans include a portfolio that removes modeling restrictions that limit the amount of energy efficiency that can be selected as a resource option.

IT IS FURTHER ORDERED that Tucson Electric Power Company shall in future Integrated Resource Plans include a portfolio that removes modeling restrictions on the economic cycling and economic retirement of coal units.

IT IS FURTHER ORDERED that by January 1, 2030, Tucson Electric Power Company's resource portfolio shall include a demand-side resource capacity equal to at least 35 percent of Tucson Electric Power Company's 2020 peak demand. The portfolio of demand-side management measures shall include rate-enabled, load-shifting technologies, including, but not limited to, demand response, energy storage, and smart thermostats, that provide customer bill savings and clean energy benefits.

IT IS FURTHER ORDERED that Tucson Electric Power Company shall demonstrate 1.3 percent annual energy efficiency measured by megawatt-hour savings over its next three-year planning period and shall report its annual energy efficiency savings in its 2023 Integrated Resource Plan.

IT IS FURTHER ORDERED that Arizona Public Service Company shall in future Integrated Resource plans include a portfolio that eliminates coal unit must-run designations.

IT IS FURTHER ORDERED that Arizona Public Service Company shall in future Integrated Resource Plans include a portfolio that removes modeling restrictions that limit the amount of energy efficiency that can be selected as a resource option.

IT IS FURTHER ORDERED that Arizona Public Service Company shall in future Integrated Resource Plans include a portfolio that removes modeling restrictions on the economic cycling and economic retirement of coal units.

IT IS FURTHER ORDERED that by January 1, 2030, Arizona Public Service Company's resource portfolio shall include a demand-side resource capacity equal to at least 35 percent of Arizona Public Service Company's 2020 peak demand. The portfolio of demand-side management measures shall include rate-enabled, load-shifting technologies, including, but not limited to, demand response, energy storage, and smart thermostats, that provide customer bill savings and clean energy benefits.

IT IS FURTHER ORDERED that Arizona Public Service Company shall demonstrate 1.3 percent annual energy efficiency measured by megawatt-hour savings over its next three-year planning period and shall report its annual energy efficiency savings in its 2023 Integrated Resource Plan.

IT IS FURTHER ORDERED that Arizona Public Service Company shall file annual reports on the accuracy of its load forecast, including weather-normalized values for energy and peak load.

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IT IS FURTHER ORDERED that Arizona Public Service Company shall in future Integrated Resource Plans include a full accounting of the sources and costs of the hydrogen fuel and any associated capital expenditures to produce that fuel.

IT IS FURTHER ORDERED that Arizona Public Service Company shall in future Integrated Resource Plans include the extension of key tax credits (i.e. the Investment Tax Credit and the Production Tax Credit) and its plan to run one of the Four Corners units seasonally.

IT IS FURTHER ORDERED that Arizona Public Service Company shall in future Integrated Resource Plans include information on how each portfolio performs in terms of total cumulative emissions reductions in addition to annual emissions numbers.

IT IS FURTHER ORDERED that the Commission adopt Ascend Analytics recommendations as detailed on pages 10 and 11 of its Redacted Revised Report dated August 12, 2021, including the recommendation that Arizona Public Service Company, Tucson Electric Power Company, and UNS Electric, Inc. use capacity expansion model in future Integrated Resource Plans (See Section 3.3.5, Supply Side, of Ascend Analytics' Revised Report).

IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson Electric Power Company, and UNS Electric, Inc. shall use and provide to the Commission the capacity expansion model used in their next Integrated Resource Plans, in addition to any hand-selected portfolio.

IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson Electric Power Company, and UNS Electric, Inc. shall each include in their next rate cases one or more proposals to rate base Demand-Side Resources investments for potential consideration by the Commission. Such proposals shall be developed with the input of interested stakeholders.

IT IS FURTHER ORDERED that the filing requirements contained in Arizona Administrative Code R14-2-703 which require the load-serving entities to file the next Integrated Resource Plans by April 1, 2022, are hereby waived.

IT IS FURTHER ORDERED that the next Integrated Resource Plans shall be filed by August 1, 2023.

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IT IS FURTHER ORDERED that Staff shall file in this docket, for the Commission's consideration, a recommended development timeline for the next Integrated Resource Plans within 90 days of the Commission's Decision in this matter.

IT IS FURTHER ORDERED that the 2020 Integrated Resource Plans are reasonable and in the public interest.

IT IS FURTHER ORDERED that the 2020 Integrated Resource Plans submitted by Arizona Public Service Company, Tucson Electric Power Company, and UNS Electric, Inc. are hereby acknowledged.

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IT IS FURTHER ORDERED that the information filed by Arizona Electric Power Cooperative, Inc. satisfies the requirements established in Decision Nos. 73884 and 75068.

IT IS FURTHER ORDERED that this Decision shall become effective immediately.

BY THE ORDER OF THE ARIZONA CORPORATION COMMISSION

CHAIRWOMAN MARQUEZ PETERSON	COMMISSIONER KENNEDY

DISSENT	Anna Tovar	
COMMISSIONER OLSON	COMMISSIONER TOVAR	COMMISSIONER O'CONNOR

IN WITNESS WHEREOF, I, MATTHEW J. NEUBERT, Executive Director of the Arizona Corporation Commission, have hereunto, set my hand and caused the official seal of this Commission to be affixed at the Capitol, in the City of Phoenix, this 2 day of March, 2022.

MATTHEW J. NEUBERT
EXECUTIVE DIRECTOR

DISSENT: ______________________

DISSENT: ______________________

EOA:ZTB:ihf/MAS

Arizona Corporation Commission - Resource Planning
Docket No. E-00000V-19-0034

Charles Wesselhoft
Pima County
32 North Stone, 21st Floor
Tucson, Arizona 85701
Charles.Wesselhoft@pcao.pima.gov
Victoria.Buhinger@pcao.pima.gov
Consented to Service by Email

Court Rich
Rose Law Group, PC
7144 East Stetson Drive
Suite 300
Scottsdale, Arizona 85251
CRich@RoseLawGroup.com
Consented to Service by Email

Jennifer Cranston
Gallagher & Kennedy, P.A
2575 East Camelback Road
Suite 1100
Phoenix, Arizona 85016-9225
lgernet@azgt.coop
jennifer.cranston@gknet.com
Consented to Service by Email

Kevin Higgins
Energy Strategies, LLC
215 South State Street
Suite 200
Salt Lake City, Utah 84111
khiggins@energystrat.com
Consented to Service by Email

Louisa Eberle
2101 Webster Street
Suite 1300
Oakland, California 94612
Sandy.bahr@sierraclub.org
katie.chamberlain@sierraclub.org
louisa.eberle@sierraclub.org
peter.morgan@sierraclub.org
Consented to Service by Email

Melissa Krueger
Pinnacle West Capital Corporation
400 North 5th Street, MS 8695
Phoenix, Arizona 85004
Melissa.Krueger@pinnaclewest.com
Kerri.Carnes@aps.com
Debra.Orr@aps.com
Theresa.Dwyer@pinnaclewest.com
Consented to Service by Email

Michael Patten
Snell & Willmer L.L.P.
400 East Van Buren
Phoenix, Arizona 85004
docket@swlaw.com
bcarroll@tep.com
jthomes@swlaw.com
mpatten@swlaw.com
mdecorse@tep.com
mderstine@swlaw.com
Consented to Service by Email

Patrick Black
Fennemore Craig, P.C.
2394 East Camelback Road
Suite 600
Phoenix, Arizona 85016
pblack@fclaw.com
lferrigni@fclaw.com
Consented to Service by Email

Robin Mitchell
Director/Chief Counsel, Legal Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007
legaldiv@azcc.gov
utildivservicebyemail@azcc.gov
Consented to Service by Email

STAFF ASSESSMENT
OF THE 2020 INTEGRATED RESOURCE PLANS

DOCKET NO. E-00000V-19-0034

DECEMBER 7, 2021

PREPARED BY UTILITIES DIVISION STAFF OF THE ARIZONA CORPORATION COMMISSION

TABLE OF CONTENT

I. EXECUTIVE SUMMARY

The Resource Planning and Procurement Rules ("IRP Rules") were adopted by the Arizona Corporation Commission ("ACC" or "Commission") on February 3, 1989, and amended by final rulemaking, effective December 20, 2010. The IRP Rules are found in the Arizona Administrative Code ("A.A.C.") at Title 14, Chapter 2, Article 7 "Resource Planning and Procurement."[1]

The IRP Rules require that 15-year Integrated Resource Plans ("IRP" or "IRPs") be prepared and submitted by "load serving entities" ("LSEs") to the Commission in each evenly numbered year on April 1.

The purpose of this report is to satisfy the requirements of A.A.C. R14-2-704(A), which requires Commission Utilities Division Staff ("Staff") file a report ("Staff Report") that contains its analysis and conclusions regarding its statewide review and assessments of the LSEs filings made under A.A.C. R14-2-703(C), (D), (E), (F), and (H) (the IRPs). In addition, Staff executed a contract with Ascend Analytics ("Ascend") and Verdant Associates (combined "the Ascend team") to serve as a third-party analyst to review the 2020 IRPs filed by Arizona Public Service Company ("APS"), Tucson Electric Power Company ("TEP"), and UNS Electric, Inc. ("UNSE"). The Ascend team's report was filed on August 11, 2021, in the docket. Subsequent to the filing, the Ascend team identified the need to make corrections to its report. As a result, a corrected copy of the Ascend team's independent review of the IRPs was filed on August 13, 2021, in the docket.[2]

Staff reviewed the 2020 IRPs, Commissioner comments, stakeholder comments and recommendations, the Ascend team's analysis and recommendations, and other relevant filings made in the docket.

Based on its review, Staff concludes:

1. APS has a stated goal of delivering 100 percent clean, carbon-free, and affordable electricity to customers by 2050. In order to achieve the 2050 goal, APS plans to have a resource energy mix which leads to 65 percent clean energy with 45 percent of customers' electricity needs served by renewable energy by 2030. APS has made a commitment to end the use of coal-fired generation by 2031. In its IRP, APS presents three portfolios which are: The Bridge, Shift, and Accelerate Portfolios. The portfolios include approximately 8,000, 9,500, and 12,000 megawatts ("MW") of additional renewable capacity, respectively.

2. APS did not select a Preferred Portfolio, as required by R14-2-703(F)(1), and states that its Five-Year Action Plan is identical for all three portfolios. APS's 2020 – 2024 Action Plan includes 2,894 MW of the following resource additions: 575 MW Demand Side Management ("DSM"), 193 MW of demand response, 408 MW of distributed energy, 962 MW of renewable energy, 750 MW of energy storage, and

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1 https://apps.azsos.gov/public_services/Title_14/14-02.pdf

2 The Ascend team produced an addendum, filed on September 21, 2021 in the docket: https://docket.images.azcc.gov/E000015791.pdf?i=1636386156053

a 6 MW microgrid. After the Five-Year Action Plan period, each portfolio's resource additions differ dramatically.

3. In TEP's 2020 IRP, TEP states that TEP's long-term strategy is now focused on completing the transition to 100 percent clean energy. TEP developed and presented a total of 15 wide ranging portfolios in its 2020 IRP. TEP's Preferred Portfolio plans to reduce its reliance on coal generation and anticipates adding 450 MW of renewable capacity by 2021 to increase the total renewable energy portfolio to over 1,000 MW, or approximately 28 percent of TEP's energy portfolio, as well as increasing investment in energy storage. TEP's Preferred Portfolio will significantly increase its solar and wind power use as well as battery storage in order to serve approximately 70 percent of its retail load by 2035 with renewable resources and achieve 80 percent reduction in Carbon Dioxide ("CO2") from 2005 levels.

4. TEP's Five-Year Action plan states it will complete the first phase of coal plant retirements when San Juan Generating Station ("SJGS") Unit 1 closes in June 2022. With that retirement, TEP will have retired 41 percent of its coal capacity since 2015. TEP will complete the build-out of planned solar and wind projects currently under contract or construction, which will double TEP's renewable energy output. TEP states it will initiate discussions with stakeholders regarding impacts due to the retirement of Springerville Generating Station("SGS") Units 1 and 2. Furthermore, TEP will continue to implement cost-effective Energy Efficiency ("EE") programs consistent with historical levels targeting 1.5 percent incremental energy savings over the prior year's retail load in each year through 2024. In addition, TEP is committed to procuring future resources through All-Source Requests for Proposal ("ASRFP") based on specific, identified system needs. Finally, TEP states it will continue preparations for joining the California Independent System Operator's ("CAISO") Western Energy Imbalance Market ("EIM") in April 2022.

5. UNSE states its 2020 IRP is designed to gradually divert the capacity mix from utilizing purchased power to predominantly utilizing self-reliant generation. Furthermore, UNSE states that it is committed to reaching a goal of supplying 50 percent of its energy to retail customers from renewable resources by 2035, while also remaining committed to reducing its carbon emissions. UNSE developed four resource portfolios in its IRP. UNSE's Preferred Portfolio has an energy mix consisting of increasing EE, a relatively consistent level of market purchases, increasing renewable energy, and consistent natural gas utilization, with a slight decrease in 2028. UNSE states that its Preferred Portfolio represents the lowest overall cost while still allowing them to reach the 50 percent goal by 2035. In addition, UNSE states this portfolio achieves the highest EE savings out of the evaluated portfolios.

6. UNSE's Five-Year Action Plan states it will continue to implement cost-effective EE programs consistent with historical levels targeting 1.5 percent incremental

energy savings over the prior year's retail load in each year through 2024. UNSE will continue to procure market-based resources to meet its short-term capacity needs through 2024. In the interim, UNSE will explore other options through its future ASRFPs to acquire alternative resources if they are proven to be more cost-effective. UNSE states it is committed to procuring future resources through ASRFPs based on specific, identified system needs. UNSE anticipates issuing an ASRFP in 2022 or 2023. UNSE is conducting studies relating to the costs and benefits of actively participating in the CAISO Western EIM.

7. The 2020 IRP produced by APS, TEP and UNSE are reasonable and in the public interest, based upon the information available to Staff at the time this report was prepared, and the requirements set forth in A.A.C. R14-2-703(C), (D), (E), (F), (H) and A.A.C. R14-2-704(B).

8. Arizona Electric Power Cooperative, Inc. ("AEPCO") has satisfied the requirements of Decision No. 73884. AEPCO has continued to participate in the IRP process by filing the information, data, criteria, and studies it has used in its 15-year planning scenarios, without the necessity of having its IRP acknowledged by the Commission.

9. The LSEs have complied with Decision No. 76632, with the following exceptions:

   a. TEP and UNSE did not include a tabular representation that provides a breakdown by capacity and energy mix contributions for each portfolio that was analyzed, similar to Table ES-2 on Page 13 of APS's 2017 IRP.

   b. APS and TEP failed to discuss the costs and benefits of natural gas storage. TEP and UNSE also failed to discuss the risks of a lack of market area natural gas storage in Arizona and only briefly describe what would be required to advance efforts to develop natural gas storage without describing the status of any efforts to develop storage or lack thereof.

   c. APS provided discussion of various storage technologies and chemistries in its 2020 IRP in the titled "Energy Storage" section but provided no analysis of anticipated future energy storage cost declines of these technologies.

   d. Staff has requested that APS, TEP, and UNSE identify where this information can be found. Although this information is omitted from the 2020 IRPs, Staff believes the IRPs are reasonable and in the public interest.

10. Each 2020 IRP (except AEPCO's) meets the requirements of the Annual Renewable Energy Requirement ("ARER"), the Distributed Renewable Energy Requirement, and the Energy Efficiency Standard.

11. The LSE load forecasts and IRPs were developed before the onset of the COVID-19 pandemic. As a result, the economic impacts of the pandemic, and the associated

impact on future electric demand, could not have been adequately considered. It is unclear what changes to the Action Plans, if any, would be required based on these factors.

12. APS, TEP, and UNSE have included a reasonable range of technologies and associated costs in the 2020 IRPs.

13. The price of natural gas has both short- and long-term impacts on an LSE's resource procurement decisions. Given the expressed desire by APS, TEP, and UNSE, in the 2020 IRPs, to achieve significant carbon emissions reductions, the impact of a wide range of natural gas prices on resource procurement decisions needs to be thoroughly discussed in the IRP.

14. Forecasting the future cost of CO2 will continue to play an important role in understanding the costs and benefits of the various portfolios presented by each LSE in its IRP.

15. Participation in regional markets, such as the EIM, may provide benefits to ratepayers and result in more efficient resource procurement. Therefore, APS, TEP, and UNSE should improve future IRPs by analyzing to what extent regional market participation affects near- and long-term resource procurement actions.

16. The TEP and UNSE IRPs lack sufficient supporting information required by A.A.C. R14-2-703(D)(1)(a), R14-2-703(D)(14), R14-2-703(D)(17), R14-2-703(E), and R14-2-703(F)(3) (see Section V(G)(5) of the Staff Report for further discussion).

17. Existing generation resources that emit carbon will have to be retired at some point for the LSEs to achieve the goals established in the 2020 IRPs. Therefore, the inclusion of a robust retirement analysis in future IRPs is necessary given these commitments. A robust retirement analysis should identify optimal resource retirement dates and quantify cost savings to ratepayers. Several stakeholders and Commissioners expressed questions and/or concerns with the identification of "must run" resources and the retirement dates presented by each LSE for various resources. The facts and circumstances around the operation of a utility's generation resources are not self-evident and should be fully explained and accompanied by supporting analysis so that the Commission and stakeholders understand the basis of an LSE's decision making.

18. There are many paths that can be taken in order to achieve significant carbon emission reductions. The analysis of a wide range of portfolios helps Commissioners and stakeholders understand the costs and benefits of achieving these reductions. In addition to understanding the costs and benefits, analyzing a wide range of portfolios ensures the optimal or least cost portfolio could be selected so that the goals of the LSE can be satisfied.

19. The LSEs state that clean and renewable energy technologies are continuing to decline in cost and that the adoption and use of these technologies can help lower costs to ratepayers. The costs and benefits of adopting a 100 percent reduction in emissions will need to be continuously evaluated and presented in future IRP proceedings.

20. In future IRPs, the issue of resource adequacy should be discussed more thoroughly, and actions taken to address the issue of resource adequacy should be fully supported. On December 18, 2020, the Western Electricity Coordinating Council ("WECC") released a report titled "The Western Assessment of Resource Adequacy Report" in which, WECC found that traditional methods of resource planning will not be adequate in the future due to the increasing variability on the system and if high levels of resource adequacy are to be preserved, resource planning methods and practices must adapt. Therefore, LSEs should analyze the resource adequacy implications of each of their scenarios, present the conclusions of this analysis and explanations of the methods used, and describe their efforts to adapt their resource adequacy analysis methods and practices to address increasing variability on the system.

21. Given the commitments made by APS, TEP, and UNSE to reduce emissions, it would be beneficial for each LSE to further explore broad environmental costs and benefits of the portfolios presented in each IRP. R14-2-704(B) requires the Commission consider the environmental impacts of resource choices and alternatives, the degree to which the LSE considered all relevant resources, risk, and uncertainties, and the degree to which the LSE's IRP is in the best interest of its customers in determining the public interest (R14-2-704(B)(7)-(9)).

22. R14-2-703(D)(17) requires that the IRPs address the adverse environmental impacts of power production. Therefore, APS, TEP, and UNSE should present information about the broader environmental impacts (e.g., societal costs of carbon emissions and water consumption associated with their resource choices) in their scenario analyses and IRPs, so the Commission and stakeholders have the benefit of this information, as supported under the IRP Rules.

23. A.A.C. R14-2-703 requires that the LSEs file the IRPs by April 1 of each even year. The filing requirements for the current IRP cycle have been established by Decision No. 76632, which also waived the relevant filing requirements in the IRP Rules. Furthermore, Decision No. 77696, ultimately required the 2020 IRPs be filed by August 26, 2020. Given these modifications to the filing requirements, the LSEs are unable to file the next IRPs, while utilizing a three-year development process, by April 1, 2022, which is the filing requirement for the next IRPs specified by A.A.C. R14-2-703.

24. Consistent with this IRP cycle and Commission Decision No. 76632, a three-year process should be utilized for the development of the next IRPs.

25. Ascend notes that, "overall, the discussion of gas storage is brief and does not provide a detailed analysis of the arguments for or against developing natural gas storage in Arizona. Future IRPs should provide additional in-depth analysis related to system reliability and the risks/consequences of pipeline distribution." Furthermore, the Ascend team states, the recent "situation on the Texas grid in February 2021 highlighted the need for utilities to investigate the interconnected risks of the gas system failing to deliver adequate supply to power plants during periods of extreme weather. While Arizona is unlikely to experience the same cold weather conditions [as Texas did in February 2021], we recommend APS include in their next IRP an analysis of power system resiliency to extreme weather, including correlated risks to both the power and gas systems. Gas storage could potentially provide a hedge against natural gas supply interruptions and price shocks that would ultimately benefit APS customers."

26. Ascend notes, "policy and economic trends portend a decline in the demand for natural gas. As renewables generate more of the system energy, gas units' capacity factors will decline. At the same time, air source heat pumps are expected to reduce residential and commercial end use of natural gas. The implications of winding down the gas system as well as replacing natural gas with hydrogen and/or renewable natural gas should be studied by APS in the next IRP as part of the broader push for decarbonization." TEP and UNSE should also study these implications in future IRPs.

Staff recommends that:

1. APS, TEP, and UNSE include in future IRPs a comprehensive analysis of power system resiliency to extreme weather, including correlated risks to both the power and gas systems.

2. APS, TEP, and UNSE file, as a compliance item in this docket, updated Five-Year Action Plans that describe whether near-term resource selections have been impacted due to changes in the LSE's load forecast attributable to the COVID-19 pandemic within 90 days of the Commission's Decision in this matter.

3. APS, TEP, and UNSE include in future IRPs a dedicated section that explicitly discusses the LSE's natural gas price assumptions, the resulting impact of those assumptions on the LSE's short- and long-term resource procurement decisions, and the implications of declining natural gas usage as the LSEs shift resource mixes to achieve emissions reductions.

4. APS, TEP, and UNSE closely monitor federal legislation, and any other relevant legislation, related to a carbon tax and include in future IRPs a relevant discussion of the impacts of such legislation on the development of the IRP.

5. APS, TEP, and UNSE include in future IRPs a discussion of participation in regional markets and the effects of that participation on near and long-term resource procurement actions.
6. TEP and UNSE include sufficient information in future IRPs regarding environmental considerations, as required by the IRP Rules.

7. The Commission order APS, TEP, and UNSE to include robust retirement analyses in future IRPs. Future IRPs should include a dedicated, comprehensive, analysis describing how the LSE evaluated the operations of its current resources, how retirement dates were selected, and why, and what the economic impact to ratepayers will be.

8. The Commission order APS, TEP, and UNSE to include in future IRPs an analysis of, at minimum 10, resource portfolios that are designed to evaluate the range of resource procurement actions, and their respective costs and benefits, that can be taken to achieve the emissions reductions goals specified by each in its 2020 IRP. The analysis and presentation of these resource portfolios should be used to support APS, TEP, and UNSE's desire to achieve significant emissions reductions.

9. The Commission order APS, TEP, and UNSE to include in future IRPs a comprehensive analysis that presents the costs and benefits of their emissions reduction commitments, compared to an approach absent these commitments, to their ratepayers.

10. APS, TEP, and UNSE include in future IRPs, a comprehensive discussion regarding how the LSE's methods for addressing resource adequacy are being adapted to address concerns with increasing variability on the bulk electric system.

11. The Commission adopt the Ascend team's recommendations as detailed on pages 10 and 11 of its Redacted Revised Report dated August 12, 2021.

12. The Commission waive the filing requirements contained in A.A.C. R14-2-703 which require the LSEs to file the next IRPs by April 1, 2022.

13. The Commission require the next IRPs to be filed by August 1, 2023.

14. The Commission order Staff to file in this docket, for the Commission's consideration, a recommended development timeline for the next IRPs within 90 days of the Commission's decision in this matter.

15. The Commission find that the 2020 IRPs are reasonable and in the public interest.

16. The Commission acknowledge the 2020 IRPs submitted by APS, TEP, and UNSE.

17. The Commission find that the information filed by AEPCO satisfies the requirements established in Decision Nos. 73884 and 75068.

I. BACKGROUND

A. General Overview

The Resource Planning and Procurement Rules ("IRP Rules") were adopted by the Arizona Corporation Commission ("ACC" or "Commission") on February 3, 1989, and amended by final rulemaking, effective December 20, 2010. The IRP Rules are found in the Arizona Administrative Code ("A.A.C.") at Title 14, Chapter 2, Article 7 "Resource Planning and Procurement."[3]

The IRP Rules require that 15-year Integrated Resource Plans ("IRP" or "IRPs") be prepared and submitted by "Load Serving Entities" ("LSEs") to the Commission in each evenly numbered year on April 1. The IRP Rules define a "load-serving entity" as "…a public service corporation that provides electricity generation service and operates or owns, in whole or in part, a generating facility or facilities with a capacity of at least 50 megawatts combined."[4] Based on this definition, there are four Commission regulated electric utilities that meet the definition of an LSE: Arizona Public Service Company ("APS"), Tucson Electric Power Company ("TEP"), UNS Electric Inc. ("UNSE"), and Arizona Electric Power Cooperative, Inc. ("AEPCO").[5] The second largest electric utility in Arizona, Salt River Project ("SRP"), is not subject to these rules and regulations of the Commission and is not required to file an IRP.[6]

The IRPs present scenarios and portfolios which compare the ability to reduce or shift electric usage (demand-side resources) in an equitable fashion to the ability to increase the production of electricity (supply-side resources). In a transparent process, with input from interested parties, each IRP will compare a wide range of resource options and take into consideration factors such as reliability, deliverability, cost projections, environmental impacts, and water consumption. Each LSE's IRP is intended to produce a portfolio of resources, which includes a schedule of demand-side and supply-side resources, that will provide for the continued reliable delivery of electricity to its customers at a long-term reasonable cost.

B. Purpose

The purpose of this report is to satisfy the requirements of A.A.C. R14-2-704(A), which requires Commission Utilities Division Staff ("Staff") file a report ("Staff Report") that contains its analysis and conclusions regarding its statewide review and assessments of the LSEs filings made under A.A.C. R14-2-703(C), (D), (E), (F), and (H) (the IRPs).

R14-2-704(B) requires that the Commission issue an order acknowledging a LSE's resource plan or issue an order stating the reasons for not acknowledging the resource plan. Furthermore, the IRP Rules require that the Commission shall order an acknowledgment of a LSE's resource plan, with or without amendment, if the Commission determines that the resource

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[3] https://apps.azsos.gov/public_services/Title_14/14-02.pdf

[4] A.A.C. § R14-2-701(26).

[5] AEPCO is unique among LSEs in Arizona in that all its energy sales are at the wholesale level and it serves no retail load. The Commission acknowledged AEPCO's unique status by ordering specific IRP data submittal requirements for AEPCO's future IRP filings in Decision No. 73884 (May 8, 2013).

[6] SRP's 2017 – 2018 IRP can be found here: https://www.srpnet.com/about/stations/pdfx/2018irp.pdf

plan complies with the requirements of the IRP Rules and the LSE's resource plan is reasonable and in the public interest, based on the information available to the Commission at the time and considering the following factors:

1. The total cost of electric energy services;

2. The degree to which the factors that affect demand, including demand management, have been taken into account;

3. The degree to which supply alternatives, such as self-generation, have been taken into account;

4. Uncertainty in demand and supply analyses, forecasts, and plans, and whether plans are sufficiently flexible to enable the utility to respond to unforeseen changes in supply and demand factors;

5. The reliability of power supplies, including fuel diversity and non-cost considerations;

6. The reliability of the transmission grid;

7. The environmental impacts of resource choices and alternatives;

8. The degree to which the LSE considered all relevant resources, risks, and uncertainties;

9. The degree to which the LSE's plan for future resources is in the best interest of its customers;

10. The best combination of expected costs and associated risks for the LSE and its customers; and

11. The degree to which the LSE's resource plan allows for coordinated efforts with other LSEs.

In Decision No. 75068 (May 8, 2015), the Commission acknowledged the 2014 IRPs submitted by APS, TEP, and UNSE and also found that the 2014 IRP of AEPCO satisfied the requirements established in Decision No. 73884.

In Decision No. 76632, the Commission declined to acknowledge the IRPs filed by APS, TEP, and UNSE and found that AEPCO's filing satisfied the requirements established in Decision Nos. 73884 and 75068.

C. IRP Requirements

In addition to the requirements specified in A.A.C. R14-2-703(C), (D), (E), (F), and (H) (the IRPs) and R14-2-704(B), the Commission has specified requirements for the IRPs detailed in Decision Nos. 73884, 75068, and 76632.

The Commission's Decision in the initial IRP docket (2012 IRP filings, Decision No. 73884) acknowledged the special circumstances concerning AEPCO, namely that AEPCO does not serve any retail load, and its wholesale, supply-only role has declined dramatically since 2001. Therefore, the Commission ordered AEPCO to file whatever information, data, criteria, and studies it has used in its 15-year planning studies, and that future AEPCO IRPs need not be acknowledged by the Commission.

Decision No. 73884, requires that:

1. AEPCO continue in the IRP process but without the necessity of having its future IRPs acknowledged by the Commission.

2. AEPCO shall, in future IRP filings, submit whatever information, data, criteria, and studies it has used in its 15-year planning scenarios.

3. AEPCO shall provide its Partial Requirements Members' ("PRM" load forecasts to Staff on a confidential basis when AEPCO files its IRP.

Decision No. 75068, requires that:

1. APS, TEP, and UNSE shall hold public pre-filing workshops prior to detailed portfolio planning and analysis in their future IRPs.

2. Prior to the utility-hosted pre-filing workshops, the Commission may opt to hold its own public workshop(s). The Commission may also choose to host an additional workshop or workshops at the conclusion of the utility-hosted workshops.

3. The LSEs are put on notice that in subsequent IRPs increased emphasis will be placed on the accuracy, detail, and timelines of the Three-Year Actions Plans.

4. The LSEs, except AEPCO, should file updates to the Three-Year Action Plans whenever a substantive change occurs in the near-term resource plan. These updates should include a narrative description of any substantial changes to previously filed Three-Year Action Plans. Updates to the Three-Year Action Plans filed pursuant to the process shall not require Commission or Staff approval or acknowledgement.

5. In future IRPs, the Commission may approve, approve with conditions, or disapprove each LSE's Three-Year Action Plan. Approval of the Three-Year

Action Plans shall not constitute approval of any individual project for ratemaking purposes.

Decision No. 76632, requires that:

1. The LSEs, except AEPCO, shall include in their portfolio analyses the forecasted change in costs of both established technologies and emerging technologies.

2. The LSEs, except AEPCO, shall coordinate with Staff to hold a public workshop within 60 days after filing future preliminary IRPs, for the sole purpose of discussing each portfolio that will be analyzed by the LSEs.

3. For all future IRPs submitted by APS, TEP, and UNSE, Staff shall in addition to their existing review requirements and methods, hire one or more third-party analysts to conduct an independent review of the scenarios and portfolios presented in each IRP, and of their respective costs and benefits, and to develop and present alternative scenarios and portfolios the third-party analyst deems are not adequately represented or considered in the IRP. The hiring of a third-party analyst shall require prior Commission approval.

4. The LSEs, except AEPCO, shall address natural gas storage in greater detail in future IRPs, including a discussion of efforts to develop natural gas storage, the costs and benefits of natural gas storage, and risks resulting from a lack of market area natural gas storage in Arizona. In addition, the LSEs, except AEPCO, shall include a wide variety of natural gas price scenarios in future IRP.

5. Staff shall conduct one or more EE workshops to allow stakeholders to provide input regarding the future of EE beyond the 2020 expiration date.

6. All LSEs, except AEPCO, shall include, in future IRPs, an analysis of a reasonable range of storage technologies and chemistries and an analysis of anticipated future energy storage cost declines as further discussed in Decision No. 76295.

7. All LSEs, except AEPCO, shall include a storage alternative as a resource option in future IRP, and shall include an analysis of storage alternatives into their respective processes when considering upgrades to transmission or distribution systems, or when considering new build or capacity upgrades for existing generation resources.

8. All LSEs, except AEPCO, shall include "no-growth" and "low-growth (<1 percent)" scenarios in future IRPs, until further order of the Commission.

9. APS, TEP, and UNSE, in each of their next IRPs shall analyze, along with their preferred portfolio, at least one portfolio where the addition of fossil fuel resources is no more than twenty percent (20 percent) of all the resource additions.

II. INTRODUCTION

A. Third Party Analyst

Decision No. 76632, ordered:

> "For all future IRPs submitted by APS, TEP, UNSE, Staff shall, in addition to their existing review requirements and methods, hire one or more third-party analysts to conduct an independent review of the scenarios and portfolios presented in each IRP, and of their respective costs and benefits, and to develop and present alternative scenarios and portfolios the third-party analyst deems are not adequately represented or considered in the IRP. The hiring of a third-party analyst shall require prior Commission approval."

During the Commission's March 24, 2021 Staff Open Meeting, the Commission discussed Staff's engagement with a third-party analyst pursuant to Decision No. 76632. Staff executed a contract with Ascend Analytics ("Ascend") and Verdant Associates (combined "the Ascend team") to serve as a third-party analyst to review the 2020 IRPs filed by the LSEs (APS, TEP, and UNSE). The Ascend team's scope of work included:

- Review of the IRP processes used by each LSE adhere to best practices;
- Review whether LSEs used modern modeling frameworks;
- Review if the IRPs capture an adequate set of assumptions;
- Review whether each LSE took a capacity expansion or a "by hand" portfolio scenario approach;
- Review and summarize the portfolio results for each LSE;
- Perform independent validations of portfolio results using simplified modeling approaches; by mining output data such as capacity factors, market prices, and emissions factors, Ascend will verify the reasonableness of the portfolio results;
- Identify issues and shortcomings related to the development of the LSE scenarios and portfolios;
- Identify and recommend alternative portfolios and scenarios;
- Work with the LSEs to implement study runs of the proposed alternative scenarios and receive results, compare the results with the IRPS in the areas of cost, reliability, and environmental performance;

- Recommend improvements to the IRPs and adoption of best practices;
- Review methods for capturing risks;
- Review the various assumptions used in the IRP demand forecasts including retail rates, utility demand management program offerings, Electric Vehicle ("EV") adoption forecasts, electrification assumptions, climate related demand drivers, and energy service demand assumptions; and
- Review the impacts of customer supply alternatives included in the IRPs such as solar Photovoltaics ("PV") and PV plus storage.

Decision No. 76632, requires the third-party analyst develop and present alternative scenarios and portfolios the third-party analyst deems are not adequately represented or considered in the IRP. Pursuant to this requirement, Ascend included the following portfolios because the Commission was considering the portfolios in its Proposed Energy Rules ("PER") (see Exhibit A-1 of Decision No. 78041, (the "Energy Rules"):

- 80 percent reduction in GHG emissions by 2050;
- 100 percent reduction in GHG emissions by 2050; and
- "Least-cost" portfolio through 2050

The Ascend team's report was filed on August 11, 2021, in the docket. Subsequent to the filing, the Ascend team identified the need to make corrections to its report. As a result, a corrected copy of the independent review of the IRPs was filed on August 13, 2021, in the docket.[7] An addendum, containing the Energy Rules analysis specific to UNSE, was filed in the docket on September 21, 2021.

The results of the Ascend team's analysis will be discussed in Section V of this report.

B. Modified Timeline

The timeline used for the resource planning and procurement process for 2019, 2020, and 2021 varied from the requirements specified in the IRP Rules. Historically, the IRP process has followed a two-year development timeline. In the previous IRP cycle (Docket No. E-00000V-15-0094), the Commission, by Decision, modified the process requiring the development of Preliminary IRPs and adding an additional year to develop the final IRPs. The additional time allowed increased stakeholder participation. Ultimately, Commission Decision No. 76632, modified the timeline for the current IRP process as follows:

[7] https://docket.images.azcc.gov/E000015107.pdf?i=1636386156053

IRP Process Step	Start Date	Due Date	Responsibility
Pre-Filing Workshops (optional)	8/1/2018	1/31/2019	LSEs/ACC
LSEs File Preliminary Resource Plans	4/1/2019	4/1/2019	LSEs/ACC
Staff Reviews Preliminary Plans/Stakeholder Review	4/1/2019	6/1/2019	Staff
ACC/Staff Holds Workshop(s) on Preliminary Plans	5/1/2019	6/1/2019	LSEs/ACC/Staff
ACC Open Meeting TO Review preliminary Resource Plans	7/15/2019	8/15/2019	ACC
Pre-Filing Workshop on Final Resource Plans	9/1/2019	11/30/2019	LSEs/ACC
LSEs File Final Resource Plans	4/1/2020	4/1/2020	LSEs
Stakeholder Comments Due	7/1/2020	7/1/2020	Stakeholders
LSEs' Response to Stakeholder Comments Due	7/1/2020	8/15/2020	LSEs
Staff Assessment and Proposed Order	7/1/2020	11/2/2020	Staff
ACC Holds Open Meeting Acknowledge Final IRP	1/15/2021	2/15/2021	ACC

Decision No. 77176, modified this filing timeline, providing the LSEs with an extension to file the Preliminary IRPs by August 1, 2019.

Commission Decision Nos. 77574 and 77696, further modified the filing timeline of the final IRPs to be as follows:

Modified IRP Process Step	Start Date	Due Date	Responsibility
LSE File Final IRPs	8/26/2020	8/26/2020	LSEs
Stakeholder Comments	8/26/2020	10/15/2020	Stakeholders
LSEs Response to Stakeholder Comments	8/26/2020	11/15/2020	LSEs
Staff Assessment and Proposed Order	11/15/2020	1/16/2021	ACC Staff
ACC Holds Open Meeting to vote on IRPs	2/1/2021	2/28/2021	Commissioners

C. The Commission IRP Proceedings and Workshops

On March 28, 2019, APS submitted their Historical Resource Planning ("HRP") information for 2018. On April 1, 2019, UNSE and TEP filed the HRP Filing for 2018 while AEPCO filed its Demand- and Supply-Side Data Report.

APS held its 2019 IRP Stakeholder Forum on April 4, 2019 and followed up with a Preliminary Stakeholder Forum on June 25, 2019.

On July 1, 2019, TEP filed its 2019 Preliminary IRP. AEPCO submitted IRP data as a compliance item on August 1, 2019, while APS and UNSE submitted their 2019 Preliminary IRPs as well.

On September 19, 2019, the Commission held a Stakeholder Meeting and Workshop, which was attended by APS, TEP, UNSE, and AEPCO.

On December 12, 2019, APS held an IRP Stakeholder Meeting.

AEPCO filed its Demand- and Supply-Side Data and APS submitted its HRP information for 2019 on April 1, 2020. TEP provided its Resource Planning and Procurement Filing of Historical Data for 2019 on April 17, 2020.

On May 20, 2020, TEP held a Stakeholder Workshop. APS held a Stakeholder Meeting on June 11, 2020.

On June 26, 2020, APS and TEP filed the 2020 IRPs. UNSE submitted its 2020 IRP on August 26, 2020, while AEPCO filed its 2020 IRP data as a compliance item in the docket.

APS held a Stakeholder Workshop on September 15, 2020, and then conducted an additional meeting in February 2021.

The Commission held an IRP Workshop on March 15, 2021, which was attended by the LSEs.

III. THE INTEGRATED RESOURCE PLANS

Pursuant to R14-2-703(F), an LSE shall file a 15-year resource plan (IRP). The IRP presents the LSE's plan to meet forecasted demand over a 15-year period. Pursuant to R14-2-703(F)(1), the LSE shall select a portfolio of resources ("Preferred Portfolio") based upon a comprehensive consideration of a wide range of supply- and demand-side options. The IRPs include the presentation of various portfolios of resources that have been constructed by the LSE to meet forecasted demand. In addition to the presentation of resource portfolios, each LSE presents its analysis of each portfolio. Pursuant to R14-2-703(H), the LSEs shall also include an Action Plan, based on the results of the resource planning process, that (1) includes a summary of actions to be taken on future resource acquisitions; (2) includes details on resource types, resources capacity, and resource timing; and (3) covers the three-year period following the Commission's acknowledgment of the resource plan.

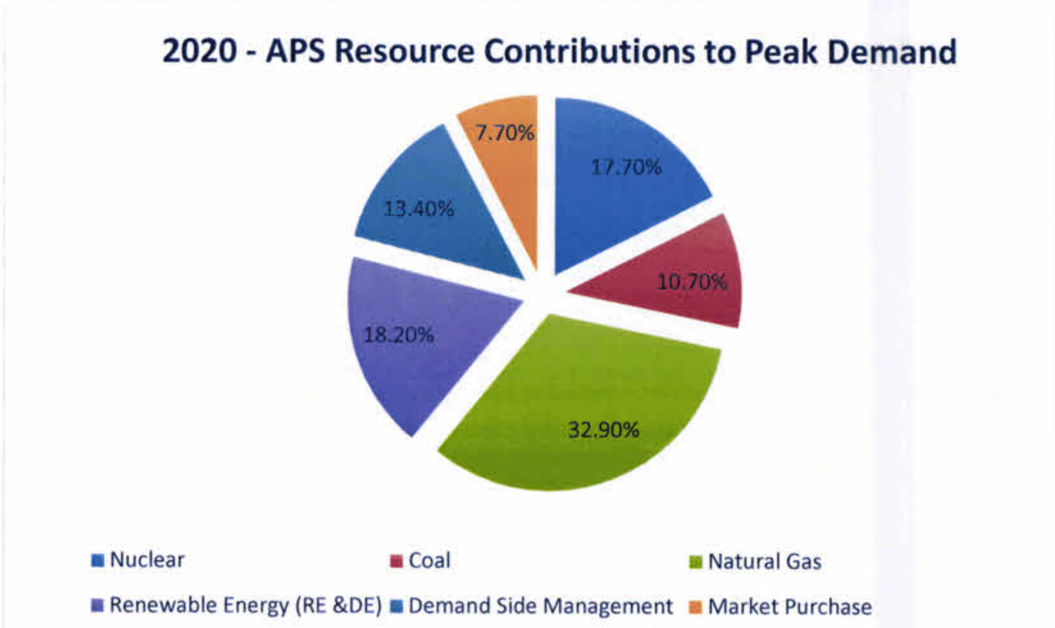
In this section of the report, Staff has summarized the 2020 IRPs filed by APS, TEP, and UNSE. In addition, Staff has provided a summary based on review of the information AEPCO has provided pursuant to the requirements of Decision No. 73884.

A. Arizona Public Service Company

1. Overview

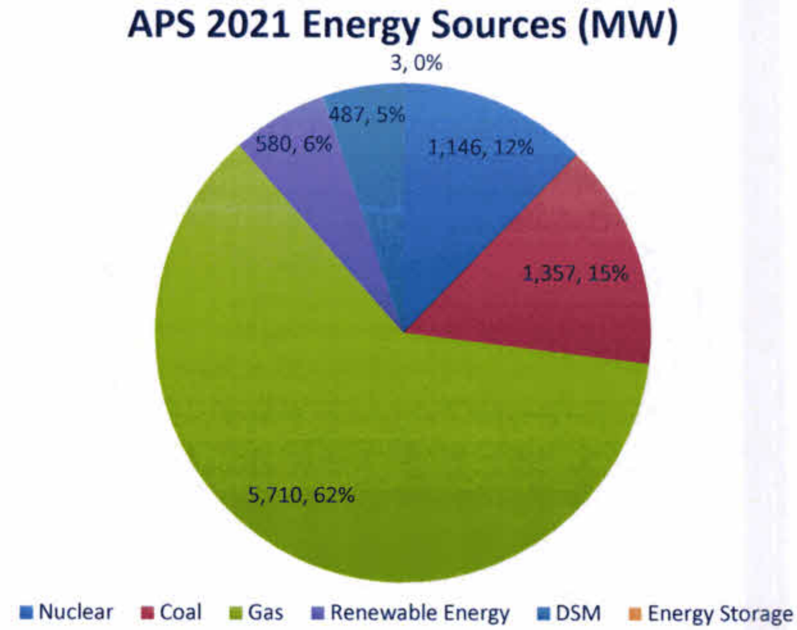
APS is the largest electric utility in Arizona, with a service territory that covers some 34,646 square miles and serves approximately 1.2 million customers across 11 of Arizona's 15 counties. APS has an estimated peak demand for 2020 of 7,875 megawatts ("MW") and plans to increase its capacity to 13,007 MW by 2032.

APS filed its 2020 IRP on June 26, 2020. According to its IRP, the breakdown of 2020 installed capacity by fuel type, based on contributions to system peak demand, is shown in the following chart:



The renewable sources utilized by the Company include Concentrated Solar Power ("CSP") as well as storage, solar PV, wind, hydro, geothermal, biomass and biogas. APS also sources its energy through distributed generation, renewable purchases, and APS-owned renewable generation. APS co-owns and operates the Palo Verde Nuclear Generating Station ("PVNGS"), which is the largest nuclear generating station in the United States and the largest producer of carbon-free energy. PVNGS generates 3,739 MW or 32 million Megawatt Hours ("MWh") of power annually with APS owning 29.1 percent of the PVNGS. This share equates to approximately 1,088 MW of capacity. The company co-owns and operates the Four Corners Power Plant ("Four Corners"), a 1,540 MW coal-fired facility located on the Navajo Indian Reservation, however this plant is slated to close by 2031, to reach the Company's clean energy goals. APS currently owns 63 percent (or 970 MW) of the capacity at Four Corners. APS is a co-owner of the Cholla Coal-Fired Power Plant ("Cholla") and operates Units 1, 2 and 3 located in northeastern Arizona near Holbrook, providing 647 MW of capacity to APS. APS owns and operates the six combustion turbine units that produce 233 MW at the Yucca Power Plant ("Yucca") and operates the steam turbine and 22 MW combustion turbine which are in southwestern Arizona. The remaining plants operated by APS include the West Phoenix Power Plant ("West PPP") as well as the Ocotillo Power Plant ("Ocotillo").

The following chart shows the forecasted 2021 breakdown in capacity by fuel type:



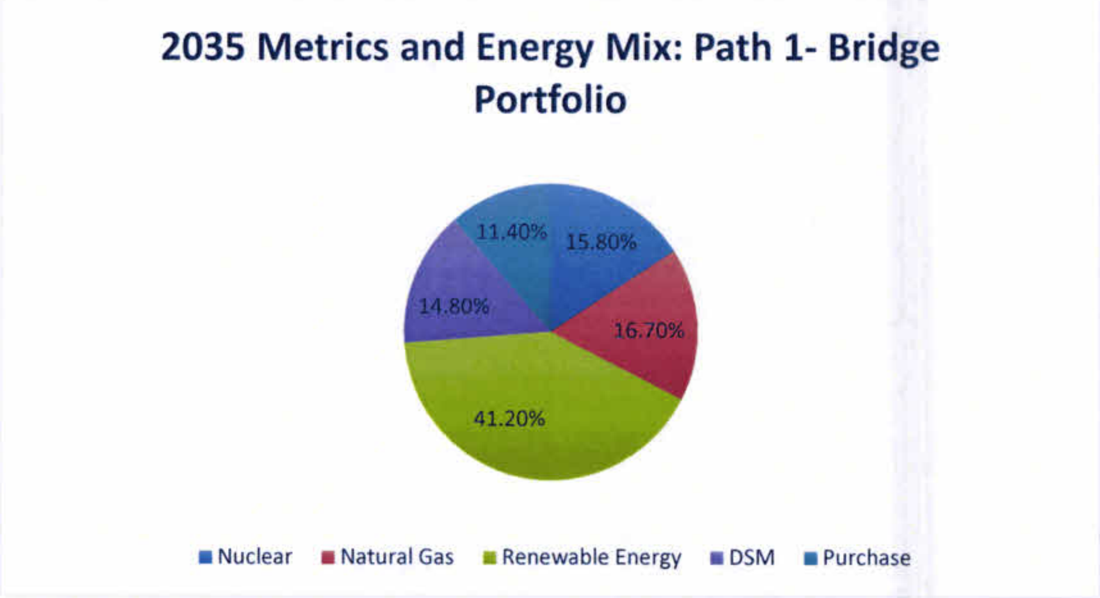
During the development of APS's IRP, APS retained Energy and Environmental Economics ("E3") to study how different clean energy policies and strategies impact its ability to maintain reliability and affordability. Before the development of its 2019 Preliminary IRP, APS shared information regarding E3's work in other jurisdictions exploring similar issues. Generally, E3's planning studies focus on questions of how to meet aggressive carbon reduction and clean energy goals in the electric sector while maintaining reliability and managing costs. One key finding that was common across E3's studies was that a technology-neutral policy focused on carbon reductions enables utilities to meet clean energy goals more affordably than policies that establish goals for specific technologies, such as clean energy standards or renewable energy standards.

APS has a stated goal of delivering 100 percent clean, carbon-free, and affordable electricity to customers by 2050. To achieve the 2050 goal, APS plans to have a resource energy mix which leads to 65 percent clean energy with 45 percent of customers' electricity needs served by renewable energy by 2030. APS has made a commitment to end the use of coal-fired generation by 2031. In its IRP, APS presents three portfolios and one alternative portfolio.

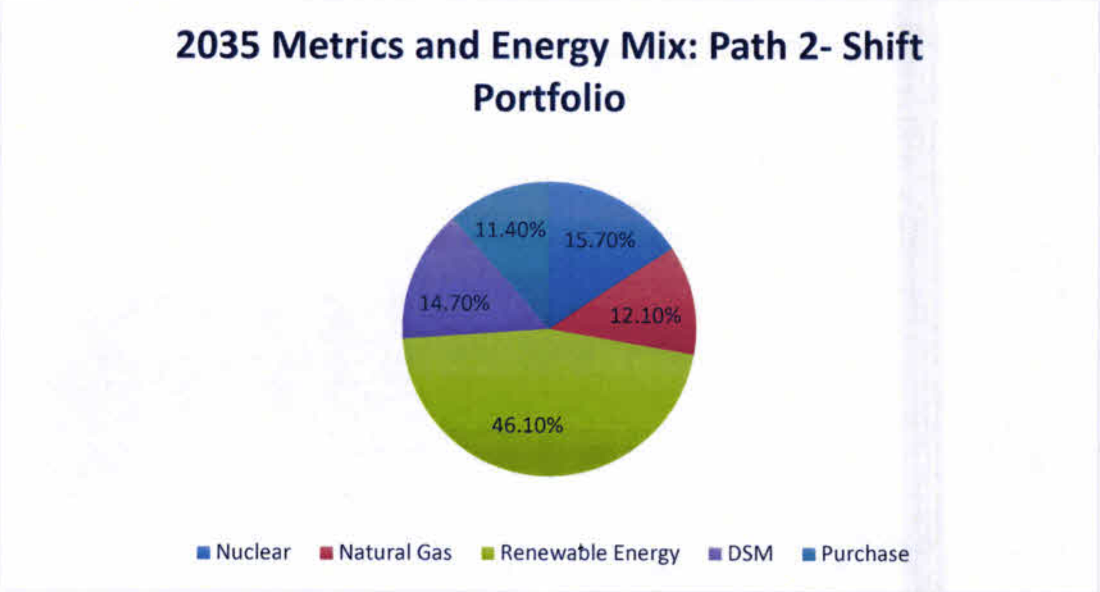
2. *Resource Portfolios*

The three portfolios presented are: The Bridge, Shift, and Accelerate Portfolios. In addition, APS presented an alternative, Technology Agnostic, portfolio that it states does not satisfy its commitment to a clean energy future.

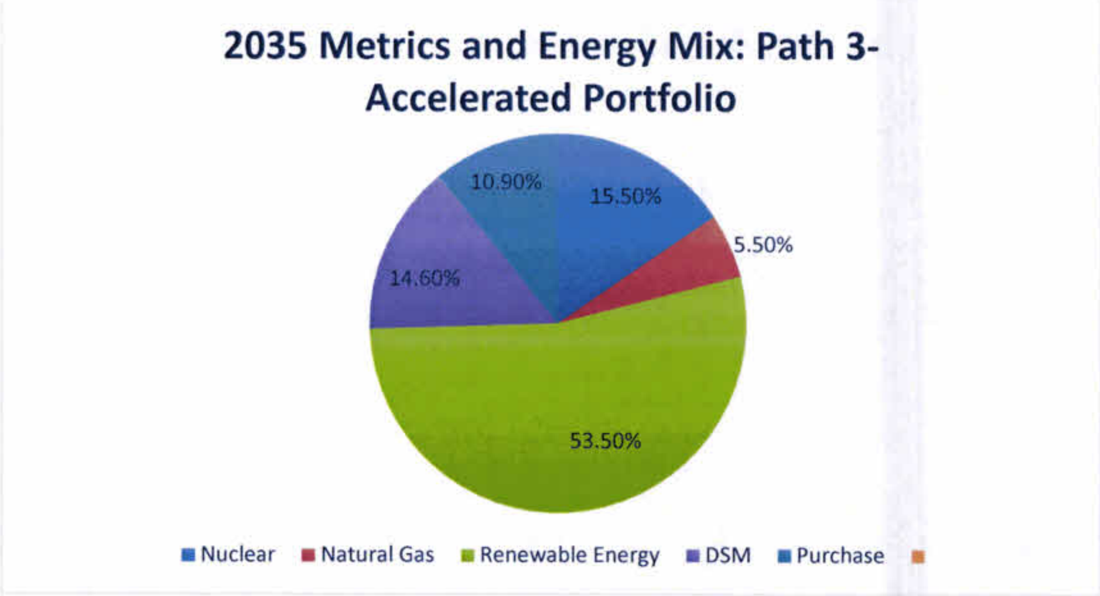
The Bridge Portfolio, shown below, consists of 79 percent clean energy, for a total of 17,170 MW of resource additions:



The Shift Portfolio includes 84 percent clean energy, for a total of 19,646 MW of resource additions:



The Accelerate Portfolio utilizes the highest percentage of clean energy at 91 percent and requires 24,911 MW of resource additions:



The Portfolios include approximately 8,000, 9,500, and 12,000 MW of additional renewable capacity, respectively. The Accelerate Portfolio also includes a decrease in natural gas utilization of approximately 1,850 MW. APS states the Technology Agnostic portfolio was created to provide a more traditional "least cost" view of the IRP, carrying significantly more gas supply and price risk than the first three portfolios.

The following table describes each portfolios carbon reduction, revenue requirement, and renewable energy standard:

Portfolio	Carbon Reduction	Revenue Requirement	Renewable Energy Standard
1-Bridge	69% in 2035 & 100% in 2050	$26.6 Billion	58% in 2035
2-Shift	77% in 2035 & 100% in 2050	$26.9 Billion	66% in 2035
3-Accelerate	86% in 2035 & 100% in 2050	$28.4 Billion	77% in 2035
4-Technology Agnostic Portfolio	33% in 2035	$24.9 Billion	15.4% in 2035

APS's IRP states,

> "The Accelerate and Technology Agnostic portfolios represent bookends of a wide range of portfolios, while Bridge and Shift represent intermediate portfolios that fill in points along the spectrum. The Technology Agnostic portfolio was developed with resource optimization software that did not impose limits on the amount of new natural gas that could be built. On the other end of the spectrum, the Accelerate portfolio featured accelerated deployment of renewable resources and energy storage systems (ESS)… The Technology Agnostic portfolio did not meet APS's clean energy commitment and was only used as a base of comparison for the other portfolios. Of the two intermediate portfolios, Bridge was designed to meet the requirements of the clean energy commitment (45 percent renewables and 65 percent clean energy resources by 2030), and Shift provides an option between Bridge and Accelerate."

The Bridge portfolio is the slowest portfolio to transform to 100 percent carbon-free energy. As well as the goal of increasing the renewable energy resources to 41.2 percent in 2035, where the other three portfolios have a higher percentage – Shift portfolio has 46.1 percent and Accelerate portfolio has 53.5 percent in 2035. The Accelerate portfolio is the fastest portfolio to reduce carbon-use by 86 percent in 2035, and to increase the resources of renewable energy by 53.5 percent in 2035. The Accelerate portfolio is the most expensive portfolio out of these three portfolios with a revenue requirement of $28.4 Billion. The Bridge and Shift portfolios have a revenue requirement of $26.6 Billion and $26.9 Billion, respectively.

With respect to the Technology Agnostic portfolio, APS states it is the least effective in reducing carbon-use and increasing renewable energy resources. In addition, the usage of natural gas will be two times that used in the Bridge portfolio which can expose ratepayers to higher costs if the price of natural gas increases.

Overall, APS's 2020 IRP results show that the system cost average will have an annual increase from 2020 until 2035. The Bridge portfolio will have a 1.3 percent system cost average increase, the Shift portfolio will have a 1.7 percent system cost average increase, and the Accelerate portfolio will have a 2.8 percent system cost average increase.

3. Action Plan

APS did not select a Preferred Portfolio, as required by R14-2-703(F)(1) and states that its Five-Year Action Plan is identical for all three portfolios. The resource additions over the Action Plan period, 2020 – 2024, are shown in the table below:

2020-2024 Resource Additions	All Path (Megawatts)
Demand Side Management ("DSM")	575
Demand Response	193

Distributed Energy	408
Renewable Energy	962
Energy Storage	750
Merchant PPA/Hydrogen-ready CTs	0
Microgrid	6
Total	**2,894**

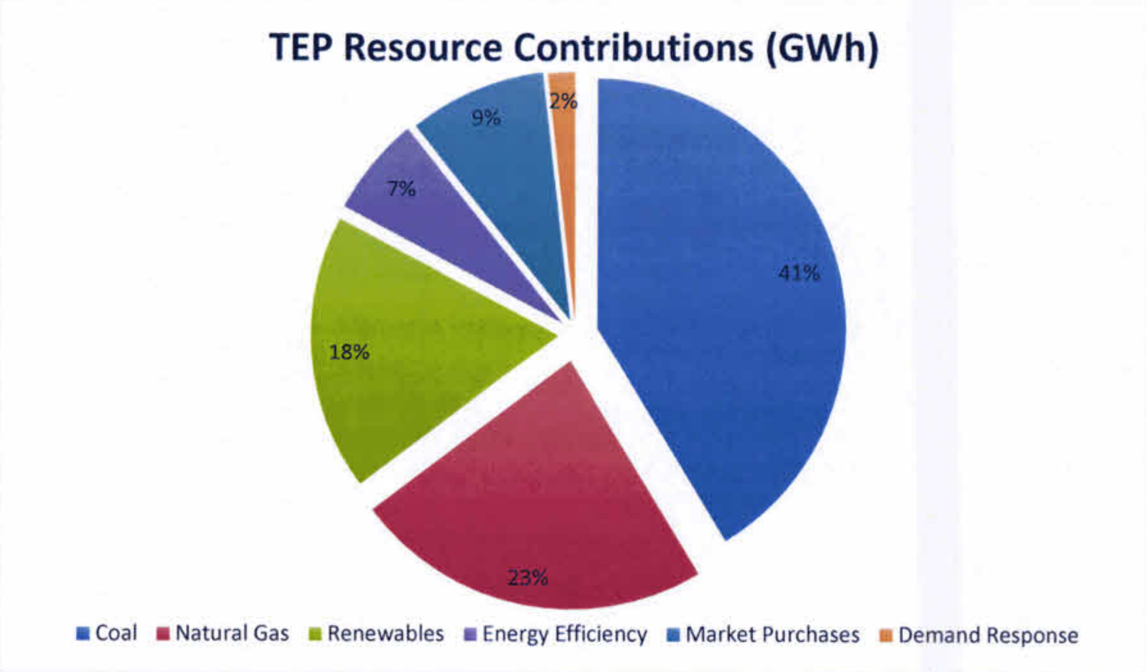
B. Tucson Electric Power Company

1. Overview

TEP is the second largest investor-owned electric utility in Arizona, and the largest corporation which is headquartered in Southern Arizona. TEP serves more than 432,000 customers in the Tucson metropolitan area located in Pima County. TEP is the principal subsidiary of its sister company, Unisource Energy Corporation, which is among a group of utilities owned by the Canadian investor-owned utility company, Fortis.

TEP filed its 2020 IRP on June 26, 2020. According to its IRP, TEP experienced a peak demand of approximately 2,370 MW with approximately 8,750 GWh of retail sales. Approximately 66 percent of this retail energy was purchased by the residential (42.2 percent) and commercial (23.9 percent) rate classes, while the remaining 34 percent was purchased by industrial (21.7 percent) and mining (12.1 percent) rate classes.

The breakdown of TEP's 2020 capacity, based on contribution to system peak demand, is shown in the following chart:



TEP's existing resource mix is described in Table 8 of Chapter 6 of its IRP. TEP's existing thermal resource capacity is 2,890 MW:

Table 8 - TEP Existing Thermal Resources

Generating Station	Unit	Fuel Type	Net Nominal Capability MW	Commercial Operation Year	Operating Agent	TEP's Share %	TEP Planning Capacity
Springerville	1	Coal	387	1985	TEP	100	387
Springerville	2	Coal	406	1990	TEP	100	406
San Juan	1	Coal	340	1976	PNM	50	170
Four Corners	4	Coal	785	1969	APS	7	55
Four Corners	5	Coal	785	1970	APS	7	55
Sundt Steam	3 & 4	Gas	260	1962-1967	TEP	100	260
Sundt RICE	1- 10	Gas	188	2019 -2020	TEP	100	188
Luna Energy Facility		Gas	555	2006	PNM	33.3	185
Gila River	2	Gas	550	2003	TEP	100	550
Gila River	3	Gas	550	2003	TEP	75	413
Combustion Turbines		Gas/Oil	210	1972-2001	TEP	100	221
Total Planning Capacity							**2,890**

TEP's coal generation assets include Springerville Generating Station ("SGS") Units 1 and 2, SJGS Unit 1, and Four Corners Units 4 and 5. TEP's natural gas generation assets include Sundt Units 3 and 4 (steam), Sundt Units 1 – 10 (Reciprocating Internal Combustion Engines "RICE"), Luna Energy Facility ("Luna"), Gila River Units 2 and 3, and several combustion turbines.

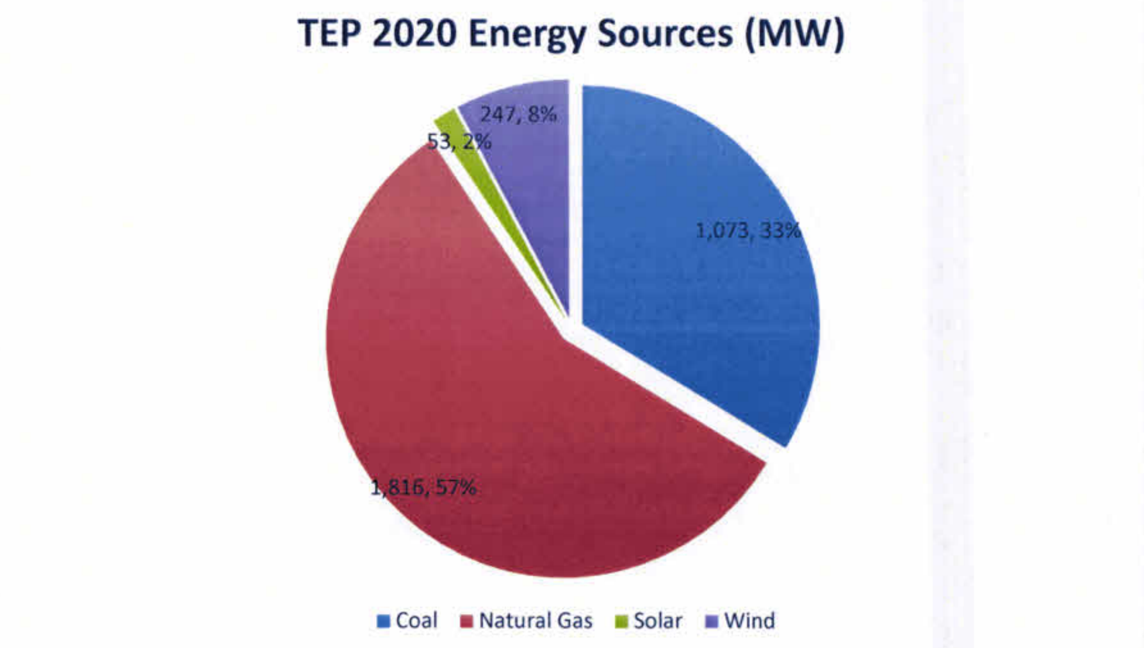
TEP's existing solar and wind renewable resources is listed in Table 12 of its IRP:

Table 12 - TEP's Existing Solar and Wind Renewable Resources

Project Name	Owned or PPA	Location	Operator	Completion/Estimated Date	Capacity MW_{AC}
Fixed Photovoltaic					
Springerville	Owned	Springerville, AZ	TEP	Dec-2010	5.3
Solon UASTP II	Owned	Tucson, AZ	TEP	Jan-2012	4.5
Gato Montes	PPA	Tucson, AZ	Astrosol	Jun-2012	5
Solon Prairie Fire	Owned	Tucson, AZ	TEP	Oct-2012	4.5
TEP Roof tops	Owned	Tucson, AZ	TEP	Dec-2012	0.04
Ft Huachuca I	Owned	Sierra Vista, AZ	TEP	Dec-2014	13.6
Ft Huachuca II	Owned	Sierra Vista, AZ	TEP	Jan-2017	4.4
Iron Horse	PPA	Tucson, AZ	Areva	April-2017	2.04
Single-Axis Tracking Photovoltaic					
Solon UASTP I	Owned	Tucson, AZ	TEP	Dec-2010	1.5
E.ON UASTP	Owned	Tucson, AZ	TEP	Dec-2010	4.8
FRV Picture Rocks	PPA	Tucson, AZ	Macquire	Oct-2012	20
NRG Solar Avra Valley	PPA	Tucson, AZ	First Solar	Oct-2012	25
E.ON Valencia	PPA	Tucson, AZ	Areva	Jul-2013	9.9
Avalon Solar I	PPA	Sahuarita, AZ	Avalon	Dec-2014	29
Red Horse Solar	PPA	Willcox, AZ	Torch	Sep-2015	41
Avalon Solar II	PPA	Sahuarita, AZ	Avalon	Feb-2016	16
Cogenera	PPA	Tucson, AZ	SunPower	Dec-2015	1.1
Concentrated Photovoltaic					
Amonix UASTP II	PPA	Tucson, AZ	Amonix	Apr-2011	2
White Mountain	Owned	Springerville, AZ	TEP	Dec-2014	8.5
Concentrated Solar Power					
Areva Solar	Owned	Tucson, AZ	TEP	Dec-2014	5
Wind					
Macho Springs	PPA	Deming, NM	Element Power	Nov-2011	50.4
Red Horse Wind	PPA	Willcox, AZ	Torch	Sep-2015	30

Notes: PPA – Purchased Power Agreement - Energy is purchased from a third-party provider
Fixed PV – Fixed Photovoltaic – Stationary Solar Panel Technology
SAT PV – Single Axis Tracking Photovoltaic
CPV – Concentrated Photovoltaic

The following chart shows the 2020 breakdown of TEP generation capacity by resource type:



As demonstrated in the above chart, TEP is currently highly dependent on natural gas and coal generation.

In TEP's 2020 IRP, TEP states that;

> "given recent declines in the cost of zero-emission renewable technologies and the current outlook that these declines will continue, TEP's long-term strategy is now focused on completing the transition to 100 percent clean energy. What remains to be determined is how quickly this transformation can occur."

TEP developed and presented a total of 15 wide ranging portfolios in its 2020 IRP with the goal of evaluating the implications of various policy positions in terms of overall cost and environmental performance. Based on its portfolio analysis, TEP concluded that a carbon emissions standard can achieve lower emissions at a lower cost than a clean or renewable energy portfolio standard.

2. Resource Portfolios

The table below provides a high-level summary of the 15 portfolios analyzed by TEP:

Portfolio Name	Renewable Energy by 2035	Carbon Emissions Reductions by 2035	Carbon Emissions Reductions by 2050	Revenue Requirement	Description
Preferred Portfolio	71%	80%		$13,534,000.00	• SGS coal supply terminates in 2030 • Inventory stockpile allows operation through 2032 (summer only) • Seasonal shutdowns begin 2023
P01aL1 M1E1	40%	51%	80%	$13,338,000.00	• 30% of sales from renewables by 2030 • 80% clean by 2050
P01bL1 M1E1	52%	52%	100%	$13,456,000.00	• 30% of sales from renewables by 2030 • 100% clean by 2050
P02aL1 M1E1	67%	69%	80%	$13,450,000.00	• 50% of sales from renewables by 2028 • 80% clean by 2050
P02bL1 M1E1	50%	67%	100%	$13,577,000.00	• 50% of sales from renewables by 2030 • 100% clean by 2050
P02cL1 M1E1	69%	69%	100%	$13,494,000.00	• 50% of sales from renewables by 2030 • 100% clean by 2050 • 35% of sales from energy efficiency by 2030 (low-cost measures)
P02dL1 M1E1	69%	70%	100%	$13,956,000.00	• 50% of sales from renewables by 2030 • 100% clean by 2050 • 35% of sales from energy efficiency by 2030 (high-cost measures)

P02eL1 M1E1	70%	70%	100%	$13,475,000.00	• 50% of sales from renewables by 2030 • 100% clean by 2050 • 35% of sales from energy efficiency by 2030 (SWEEP Modeling)
P05aL1 M1E1	70%	70%		$13,447,000.00	• 50% "clean" energy resources • 20% of demand by energy storage • 25MW of biomass • 20% of energy efficiency
P06aL1 M1E1	45%	60%		$13,309,000.00	• 45% of sales from renewables by 2035 • 30% clean energy during peak by 2035
P08aL1 M1E1	66%	78%		$13,825,000.00	• Retire all coal by end of 2027
P08bL1 M1E1	44%	59%		$13,452,000.00	• Retire SGS Unit 1 end of 2024
P09bL1 M1E1	61%	70%		$13,348,000.00	• Target CO2 emission reductions of 50% by 2025, 60% by 2030, 70% by 2035, from 2005
P10aL1 M1E1	27%	56%		$13,214,000.00	• Target CO2 emission reductions of 40% by 2025, 50% by 2030, 60% by 2035, from 2005
P16bL1 M1E1	66%	78%		$13,554,000.00	• SGS coal supply terminates in 2030 • Inventory stockpile allows operation through 2033 (summer only) • Seasonal shutdowns begin 2023

TEP's Preferred Portfolio (portfolio ID: P17aL1M1E1) achieves the following renewable energy and emission reductions targets:

Renewable Energy as a % of Retail Sales															
2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
14%	28%	31%	31%	35%	35%	36%	35%	38%	44%	44%	49%	49%	67%	67%	71%
CO2 Emissions – Percent Reduction from 2005 Levels															
24%	37%	41%	48%	52%	51%	55%	55%	60%	63%	63%	68%	70%	80%	79%	80%

TEP plans to reduce its reliance on coal generation and anticipates adding 450 MW of renewable capacity by 2021, in order to increase the total renewable energy portfolio to over 1,000 MW, or approximately 28 percent of TEP's energy portfolio, as well as increasing investment in energy storage. According to its 2020 IRP, TEP plans to significantly increase its solar and wind power use as well as battery storage in order to serve approximately 70 percent of its retail load by 2035, with renewable resources.

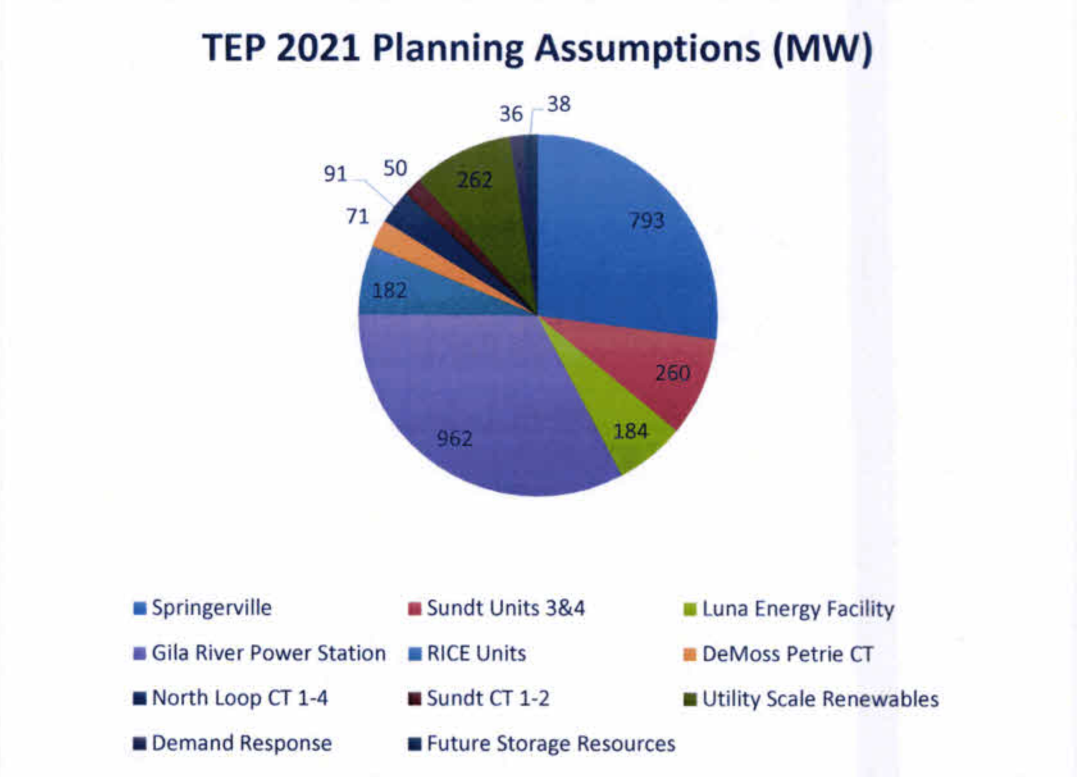
TEP has committed to gradually eliminate the use of coal-fired power plants and set a target of achieving 80 percent reduction in CO2 emissions by 2035. TEP states it will reduce its coal resource capacity by 508 MW throughout the next five years. In order to compensate for this decrease in capacity, the Company purchased Unit 2 of the Gila River Power Station ("GRPS") in its entirety (550 MW). The Company's 2020 IRP states that it requires 2,457 MW of new wind and solar power systems and 1,400 MW of battery storage. TEP plans to install 200 MW of wind and solar resources during 2020, as well as potentially adding an additional 150 MW of wind by 2021.

The following table shows the Company's Preferred Portfolio of planned retirement and plant additions:

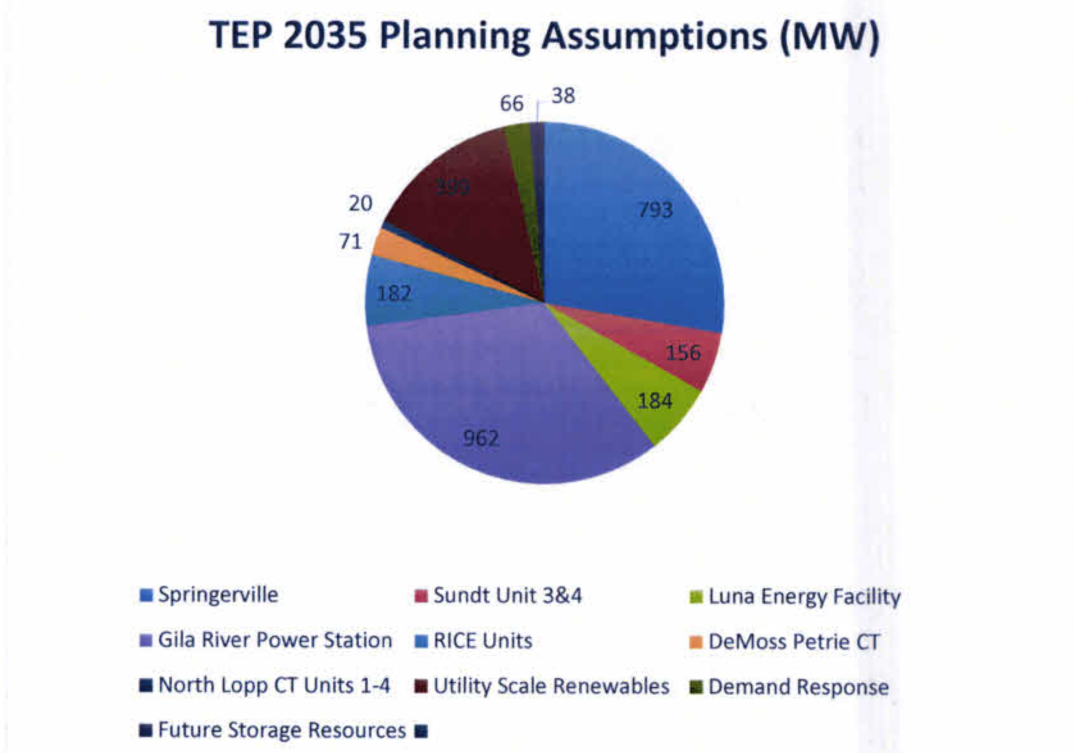
Retirements		
Plant/Unit Plant/Unit	**MW**	**Year**
SJGS Unit 1	170	2022
North Loop Units 1-3	71	2027
Sundt Combustion Turbines 1-2	50	2027
Four Corners Units 4 and 5	110	2031
Sundt Steam Unit 3	104	2032
Additions		
Plant/Technology	**MW**	**Year**
Oso Grand Wind	247	2020
Wilmot Solar	100	2021

Wilmot 4-Hr Battery Storage	30	2021
Borderlands Wind	99	2021
Distributed Generation Solar	90	2035
Energy Efficiency Savings	**716 GWh**	**Through 2035**

The following chart showcases the Company's desired procurement from its current power stations for 2020:



The following chart showcases the Company's desired procurement from its current power stations for 2035:



3. Action Plan

TEP's Five-Year Action plan states it will complete the first phase of coal plant retirements when San Juan Generating Station ("SJGS") Unit 1 closes in June 2022. With that retirement, TEP will have retired 41 percent of its coal capacity since 2015. TEP will complete the build-out of planned solar and wind projects currently under contract or construction, which will double TEP's renewable energy output. TEP states it will initiate discussions with stakeholders regarding impacts due to the retirement of SGS Units 1 and 2. Furthermore, TEP will continue to implement cost-effective EE programs consistent with historical levels targeting 1.5 percent incremental energy savings over the prior year's retail load in each year through 2024. In addition, TEP is committed to procuring future resources through All-Source Requests for Proposal based on specific, identified system needs. Finally, TEP states it will continue preparations for joining the California Independent System Operator ("CAISO") Energy Imbalance Market ("EIM") in April 2022.

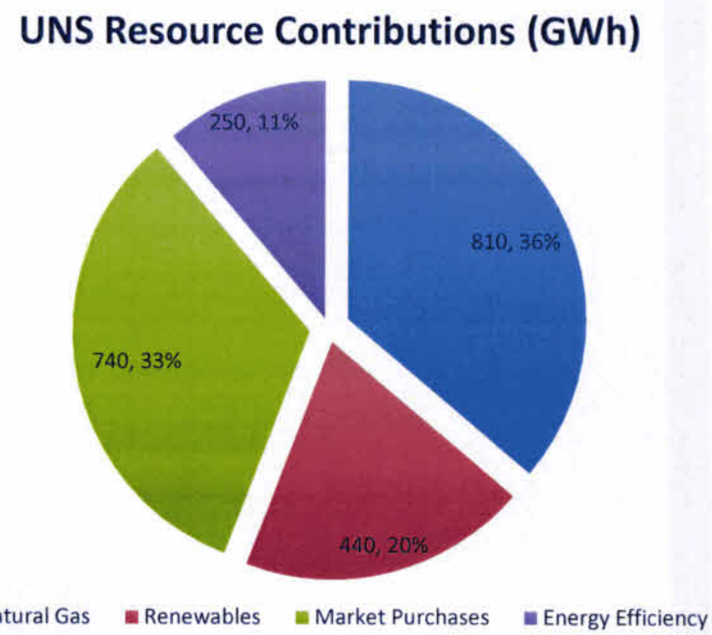
C. UNS Electric, Inc.

1. Overview

UNSE serves approximately 256,000 customers throughout northern and southern Arizona. UNSE serves mainly two distinct geographic areas – Mohave County in northwest Arizona and Santa Cruz County in southeast Arizona. UNSE is a subsidiary of Fortis, and a sister company to TEP. The Mohave County portion of the UNSE service territory includes the Kingman and Lake Havasu City areas and consists of approximately 100,000 customers. The southern territory, also known as the Santa Cruz area, encompasses the Nogales region and serves approximately 156,000 customers.

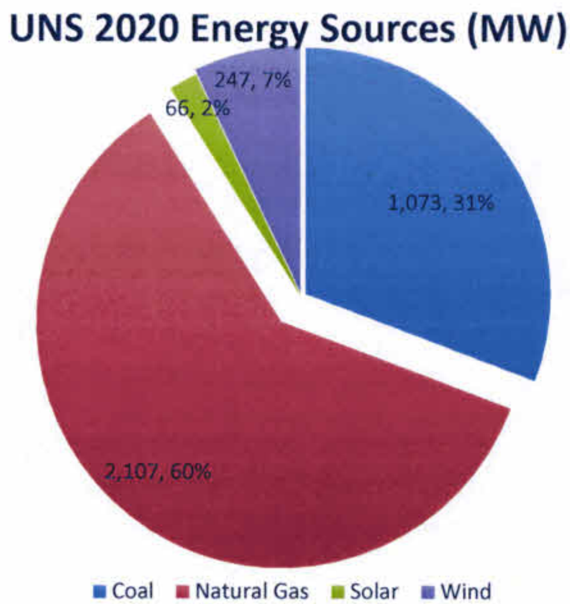
UNSE filed its 2020 IRP on August 26, 2020. According to its IRP, in 2019, UNSE experienced a coincident peak demand of approximately 453 MW between the two service areas of Mohave and Santa Cruz as well as approximately 1,700 GWh of retail sales. An estimated 93 percent of the retail energy in 2019, was sold to residential (52.2 percent) and commercial (40.8 percent) customers, while the remaining seven percent was purchased by industrial (approximately 5.7 percent) and mining (approximately 0.8 percent) customers.

The following chart shows the 2020 energy delivered to serve UNSE's load:



UNSE's current renewable energy portfolio, consisting of solar and wind technology, comprises 20 percent of its retail sales. UNSE states that with the cost of solar and wind drastically declining in recent years, stakeholders have expressed support for increasing renewable resources, so long as it does not negatively impact affordability.

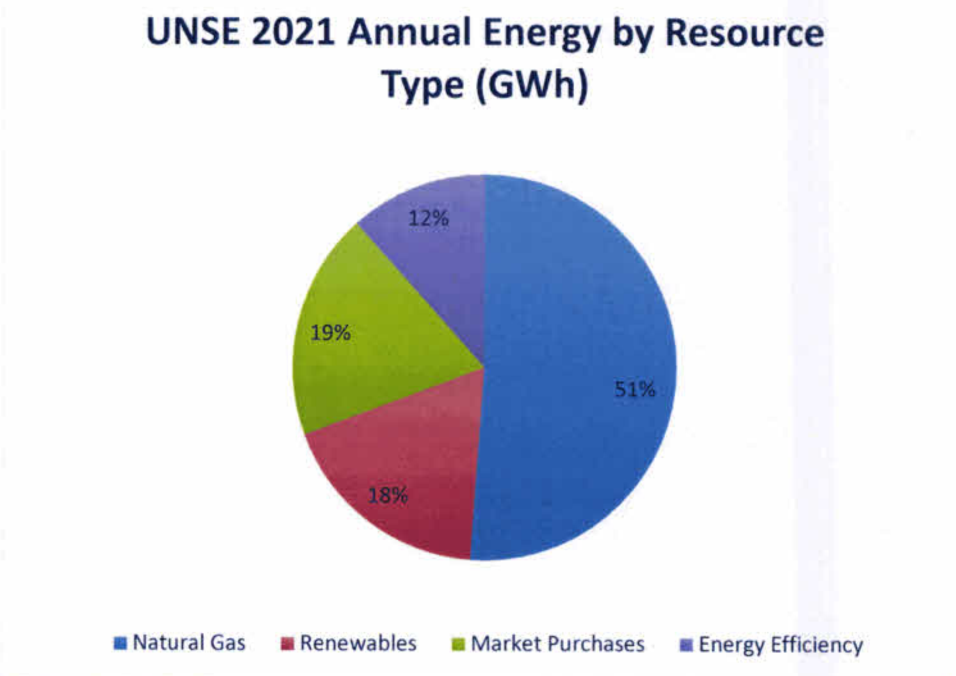
UNSE's 2020 approximate capacity mix, based on contribution to system peak demand, is shown in the following chart:



Renewables include distributed generation, renewable purchases, and UNSE-owned renewable generation. UNSE procures 90 MW of natural gas-fired combustion turbines from the Black Mountain Generating Station ("Black Mountain") and 63.5 MW from the Valencia Generating Station. UNSE also procures 138 MW from the GRPS. The remainder of the power utilized by UNSE, other than renewables, is purchased power. In 2018, UNSE began operation of its largest renewable resource, Gray Hawk Solar, which has a capacity of 46 MW.

Currently, UNSE is highly dependent on natural gas and coal, as well as a large portion of its power being purchased power. According to UNSE, its 2020 IRP is designed to gradually divert the capacity mix from utilizing purchased power to predominantly utilizing self-reliant generation. UNSE states that it is committed to reaching a goal of supplying 50 percent of its energy to retail customers from renewable resources by 2035, while also remaining committed to reducing its carbon emissions.

The following chart illustrates the Company's projected annual energy delivered by resource type for 2021:



2. *Resource Portfolios*

UNSE developed four resource portfolios based on key planning metrics. These metrics consist of cost to customers, CO2 emissions, and water consumption. The evaluated portfolios range from moderate to aggressive renewable energy and EE targets.

The following table describes the four portfolios analyzed by UNSE in its 2020 IRP:

Portfolio Requirements	
Portfolio 1	Required by ACC; 50 percent clean energy by 2035; Storage equal to 20 percent of demand; 25 MW of biomass; at least 20 percent DSM
Portfolio 2	50 percent renewables by 2035; varying levels of energy efficiency
Portfolio 3	50 percent clean energy by 2030, no fossil fuel additions
Portfolio 4	30 percent renewables by 2030

Portfolio 1, which was required by Decision No. 76632, states UNSE will supply load using 50 percent clean energy by 2035, have storage equal to 20 percent of demand, procure 25 MW of biomass, and at least 20 percent DSM. Portfolio 2 remains consistent, with a 50 percent clean energy goal by 2035, and varying levels of EE. Portfolio 3 requires 50 percent of clean energy by 2030, with no fossil fuel additions. And lastly, Portfolio 4 requires 30 percent renewables by 2030.

Three variations of Portfolio 2 were also analyzed. Overall, the portfolios were evaluated for Net Present Value Revenue Requirement ("NPVRR") under base, high, and low market scenarios ranging from approximately $2.060 million to $2.575 million.

The table below shows the revenue requirements of the different portfolios:

NPVRR for Each Portfolio and Scenario			
	Low Market	**Base Market**	**High Market**
P01aL1M1E1	$2,240,000	$2,425,000	$2,550,000
P02aL1M1E1	$2,105,000	$2,250,000	$2,440,000
P02bL1M1E1 (Preferred)	$2,060,000	$2,190,000	$2,375,000
P02cL1M1E1	$2,175,000	$2,300,000	$2,460,000
P03aL1M1E1	$2,225,000	$2,350,000	$2,500,000
P04aL1M1E1	$2,090,000	$2,240,000	$2,450,000

UNSE's Preferred Portfolio's energy mix, which has been evaluated through 2035, consists of increasing EE, a relatively consistent level of market purchases, increasing renewable energy, and consistent natural gas utilization, with a slight decrease in 2028. UNSE states that its Preferred Potfolio represents the lowest overall cost and will maintain a diverse mix of energy with renewable resources being incorporated in order to reach the 50 percent goal by 2035. In addition, UNSE states this portfolio achieves the highest EE savings out of the evaluated portfolios.

In discussing its 2020 Preferred Portfolio, UNSE states that it believes that defining the Preferred Portfolio through the results of All Source Requests for Proposals ("ASRFPs") will provide the most complete and contemporaneous set of cost and performance data on which to base firm resource decisions. Furthermore, UNSE intends to design its ASRFPs based on the results of a rigorous needs assessment and in consultation with stakeholders and the Commission. UNSE commits that ASRFPs will be technology neutral, including supply and demand-side resources and criteria for the evaluation of proposals will be determined as part of the development of the ASRFP, and will not unduly exclude any commercially available resource that can demonstrate adequate performance and cost-effectiveness.

3. Action Plan

Within UNSE's Five-Year Action Plan, it plans to add 137 MW of Natural Gas Combined Cycle ("NGCC") capacity by 2022, however, given its potential capacity need, which is less than 150 MW, compared to the typical NGCC generator capacities, UNSE states that it will likely have to join another LSE in order to build or acquire a NGCC generator.

UNSE states that renewable resources can account for 80 percent of its retail load, which poses potential issues with ramping/regulating, but due to its relationship with TEP, it is able to mitigate intermittency. UNSE has hired a third-party company, Siemens

Industry, Inc., to research and potentially improve its methodology for evaluating resource adequacy. This will be done by identifying varying net loads which will then be compared to the capacities of TEP's and UNSE's combined portfolios. Similar to TEP, UNSE continues to evaluate the development of underground natural gas storage in its IRP. The issue of resource adequacy will be discussed further in Section V(H)(1) of this report.

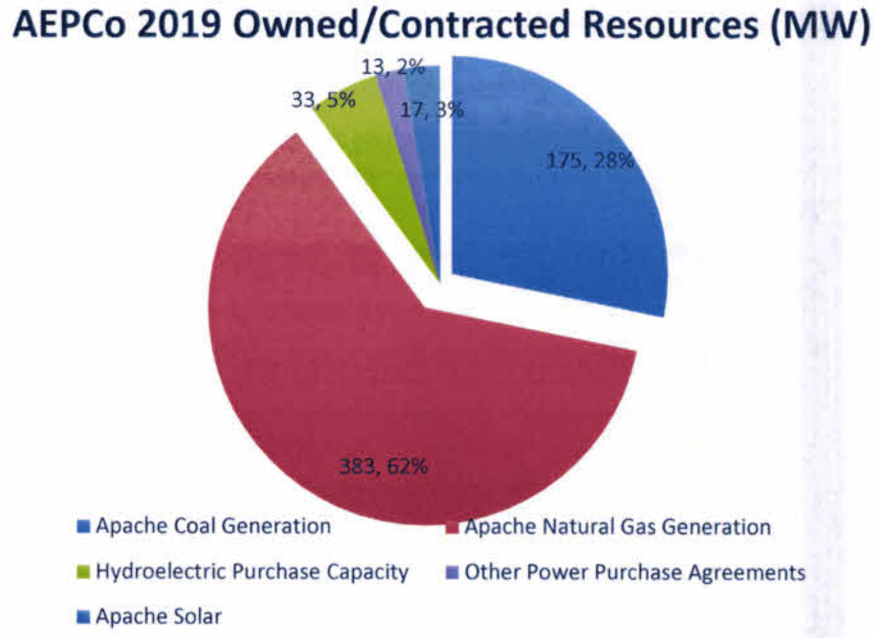
D. Arizona Electric Power Cooperative, Inc.

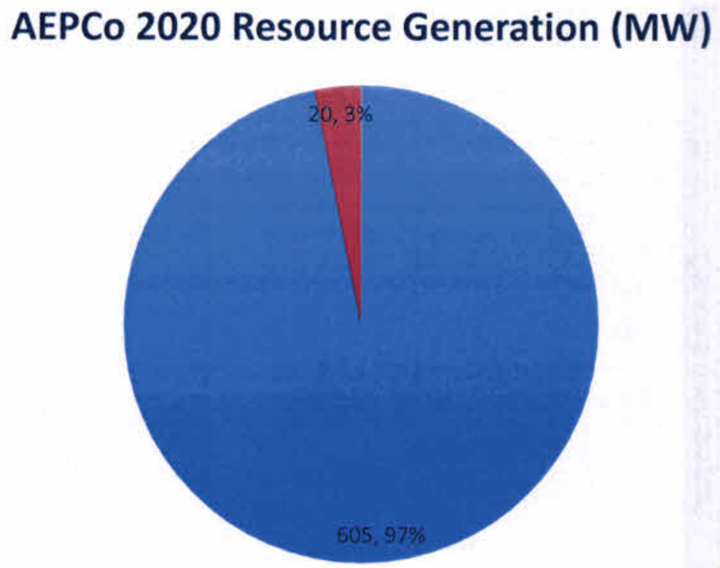
AEPCO is the generation cooperative serving six distribution cooperatives - Duncan Valley Electric Cooperative ("DVEC"), Graham County Electric Cooperative ("GCEC"), Mohave Electric Cooperative ("MEC"), Sulphur Springs Valley Electric Cooperative ("SSVEC"), Trico Electric Cooperative ("TEC"), and Anza Electric Cooperative ("AEC"). Each of these distribution cooperatives is located throughout Arizona, except for AEC, which is in Anza, California. Through these cooperatives, the Company serves approximately 420,000 customers.

Three of the distribution cooperatives served by AEPCO, namely DVEC, GCEC and AEC are all-requirements members, meaning AEPCO is responsible for planning and providing all current and future power and energy needs for these members. The remaining members are partial-requirements members. AEPCO is one of 62 cooperatives in the nation which provides both generation and transmission. The Company merged with the Southwest Transmission Cooperative in 2016. Arizona Generation and Transmission ("G&T") refers to the collective of AEPCO's G&T services as well as the Sierra Southwest Cooperative Service ("Sierra"). The Company is a provider and owner for the three All Requirement Members ("ARM") and three PRM Distribution Cooperatives.

Due to the nature of AEPCO's relationships with its member cooperatives, AEPCO is obligated to plan for the future needs of its ARM. Consistent with Decision No. 75269, AEPCO's IRP includes the gap between the Company's resource needs and resources available as well as additional resource options which the Company researched to meet its resource needs.

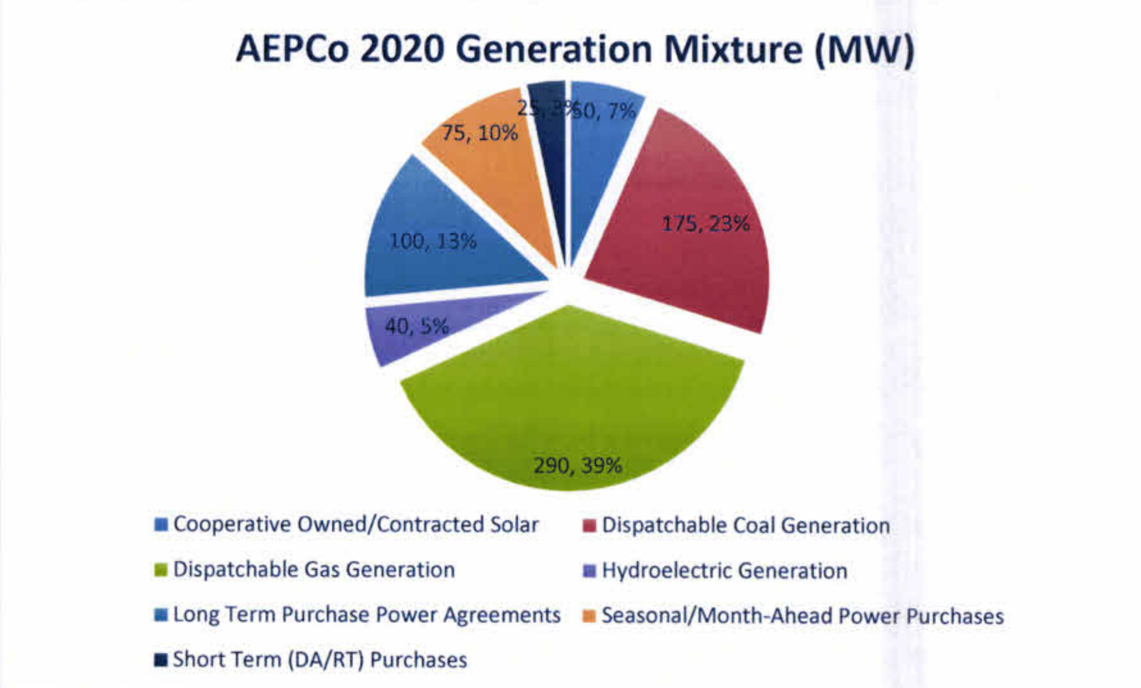
AEPCO's 2019 resource portfolio of AEPCO owned/contracted resources as well as the 2020 approximate capacity mix, based on contribution to system peak demand, is shown in the following chart:





AEPCO owns and operates the Apache Generating Station in Cochise County, which can generate 605 MW of combined generating capacity. The plant consists of three steam generating units with two burning natural gas as the primary fuel and the third being able to use either natural gas or coal as its primary fuel, as well as being able to burn both fuels simultaneously. This plant includes four gas turbines. AEPCO also owns and operates the Apache Solar Project which consists of over 77,000 solar panels that are capable of producing 20 MW of renewable power to the ARM and PRM Distribution Cooperatives as well as Electrical District No. 2, which is a public power operation in Casa Grande.

The following chart represents the energy mixture that AEPCO utilizes. This includes a combination of resource types such as dispatchable resources (natural gas, coal, and hydroelectric) as well as resources which are non-dispatchable such as wholesale solar and market purchases. This, however, does not include the retail renewable generation of the Company's Distribution Cooperative members which is approximately 53 MW.



AEPCO states that the Arizona G&T Cooperatives are committed to diversifying their energy portfolios, which includes power sources such as natural gas, coal, solar, and hydropower. AEPCO is researching adding wind energy transmission to the Apache Station, while also improving battery storage in order to maximize intermittent solar and wind generation. In doing so, AEPCO states this will provide customers with more cost-effective and reliable renewable power.

AEPCO converted its Steam Generating Unit 2 from coal-burning to natural gas as its primary fuel. The Steam Generating Unit 1 already uses natural gas for its primary fuel, while the Steam Generating Unit 3 has the capability to utilize either natural gas or coal for the primary fuel, as well as the ability to burn both fuels simultaneously.

E. Summary of 2020 Preferred Portfolios

1. Change in Capacity Mix

The following tables present the change in capacity for each Preferred Portfolio presented by APS, TEP, and UNSE. APS did not select a Preferred Portfolio; it's Bridge Portfolio is presented as a basis of comparison with the others.

APS Bridge Portfolio:

Resource	2021 Capacity (MW)	2035 Capacity (MW)	Percent Change
Nuclear	1,146	1,146	0%
Coal	1,357	0	100% Decrease
Natural Gas	5,225	3,596	31.2% Decrease
Renewable Energy	485	9,830	1,927% Increase
DSM	21	337	1,505% Increase
Energy Efficiency	105	1,207	1,050% Increase
Battery Storage	0	486	100% Increase

TEP Preferred Portfolio:

Resource	2021 Capacity (MW)	2035 Capacity (MW)	Percent Change
Nuclear	0	0	0%
Coal	1,073	0	100% Decrease
Natural Gas	1,798	1,502	16.5% Decrease
Renewable Energy	629	2,544	304.5% Increase
Battery Storage	50	50	0%
Energy Efficiency	182	732	302% Increase

UNSE Preferred Portfolio:

Resource	2021 Capacity (MW)	2035 Capacity (MW)	Percent Change
Natural Gas	282	382	35% Increase
Renewable Energy	104	338	225% Increase
Battery Storage	0	70	100% Increase
Energy Efficiency	200	750	275% Increase

The following charts compare the capacity mix change that will occur under the Preferred Portfolios presented in the 2020 IRPs filed by APS, TEP, and UNSE, based on contribution to system peak demand:

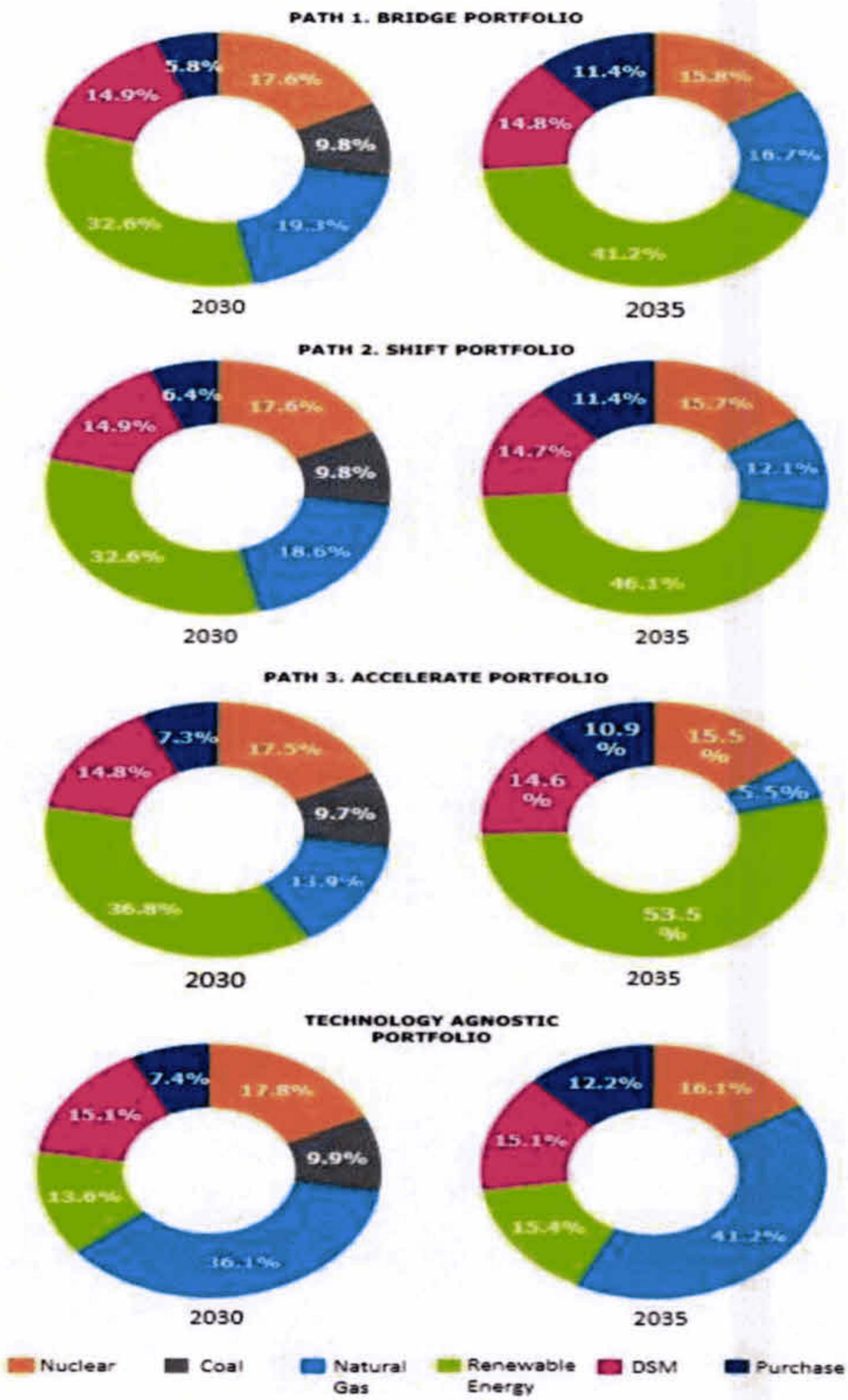
Resource	2021 Capacity (MW)	2035 Capacity (MW)	Percent Change
Nuclear	0	1,146	0%
Coal	2,430	0	100% Decrease
Natural Gas	7,305	5,480	25.00% Decrease
Renewable Energy	1,218	12,712	944% Increase

Battery Storage	50	606	1,112% Increase
Energy Efficiency	487	2,689	452% Increase

2. Change in Energy Mix

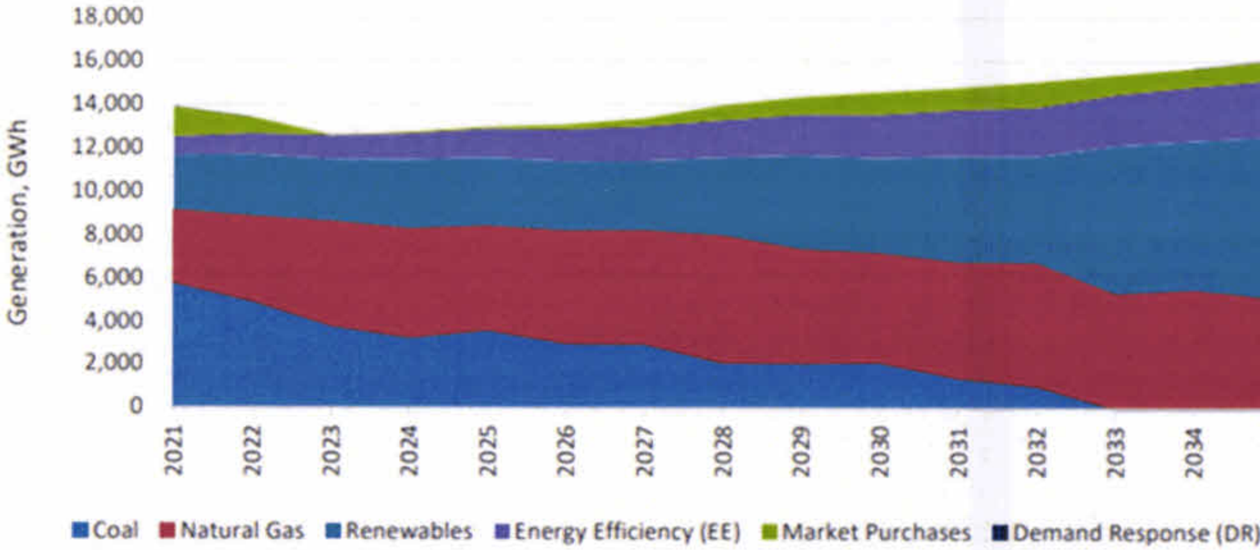
The following graphic illustrates the change in energy mix over the 15-year planning period for the three portfolios presented by APS in its 2020 IRP:

FIGURE 7-5. 2030 & 2035 ENERGY MIX



Source: APS's 2020 IRP, Page 136, Figure 7-5. 2030 and 2035 – Energy Mix.

The following graphic illustrates the change in energy mix over the 15-year planning period for TEP's Preferred Portfolio, as presented in its 2020 IRP:



Source: TEP's IRP, Page 175, Chart 57 - Preferred Portfolio, Annual Energy by Resource Type.

The following graphic illustrates the change in energy mix over the 15-year planning period for UNSE's Preferred Portfolio, as presented in its 2020 IRP:

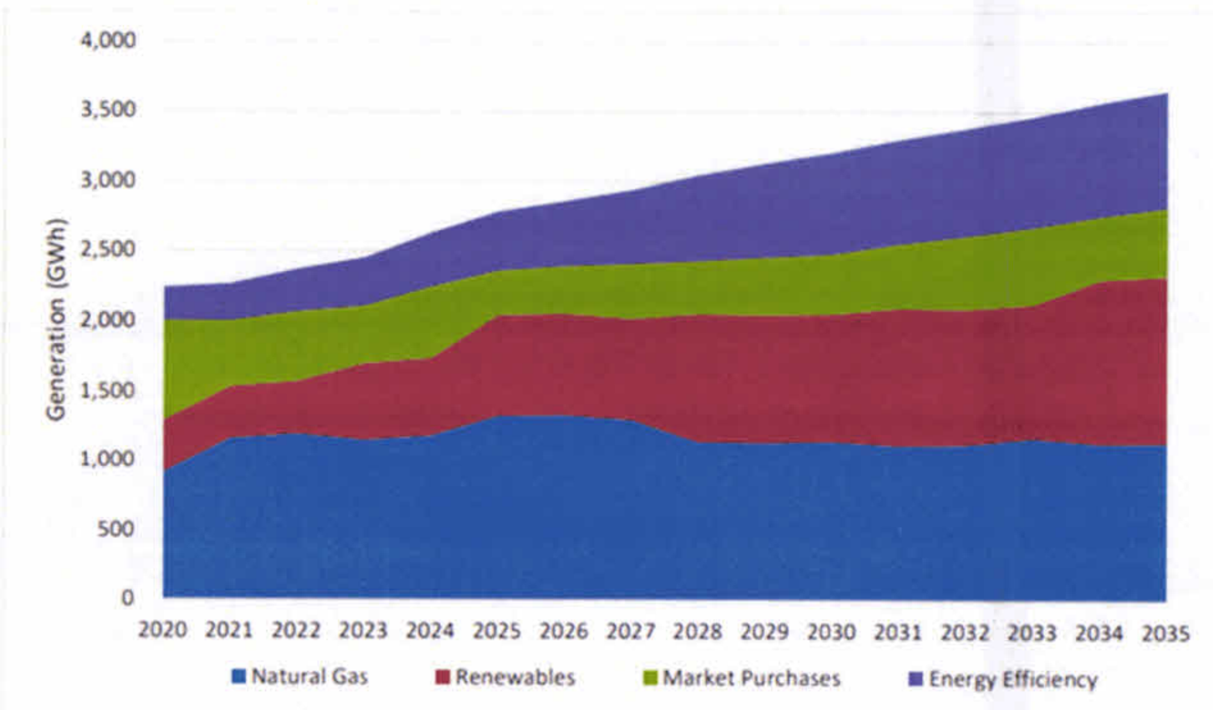


Figure 4: UNSE's IRP, Page 115, Chart 34 - Reference Portfolio, Annual Energy by Resource Type.

3. Retirements

All the portfolios presented by APS for the 2020 IRP have in common the commitment to exit coal generation by 2031. The following is a summary of retirements for APS:

- Ocotillo Steam Units 1 and 2 were retired on March 22, 2019. They had reached the end of their useful life and it had become difficult to maintain the units and acquire necessary parts for repair. Due to the importance of the location of the plant in the Valley to serve Valley load, five start combustion turbines were built at the site and came on-line in 2019.

- Cholla Units 1 and 3 will no longer burn coal past April 2025. However, APS continues evaluating its options with these plants and will inform the Commission with the decision on this matter.

- Four Corners Units 4 and 5 will cease operations no later than 2031, to meet the goal of ending the use of coal-fired generation as part of APS's clean energy commitment.

TEP plans to end the use of coal-fired generation entirely by 2032. TEP states that coal continues to provide firm capacity, with the surety of a solid fuel supply. TEP's reductions in coal capacity will occur in stages, until it can be replaced by cleaner resources. TEP states it will work with local leaders and employees in coal communities, to prepare for the retirement of 1,073 MW of coal capacity and 225 MW of natural gas capacity.

TEP plans to retire the following generation plants in the coming future:

- SJGS Unit 1 located in New Mexico: TEP has ownership of 50 percent (170 MW). With the closure of the plant, expected for 2022, the company will have retired 638 MW, representing 41 percent of its coal capacity since 2015.

- Four Corners Units 4 and 5 located in New Mexico: TEP owns seven percent of each plant (110 MW). They will be retired in 2031.

- Springville Units 1 and 2 located in Arizona: TEP owns both plants. With a capacity of 387 MW (Unit 1) and 406 MW (Unit 2), they are planned to be retired by 2027 and 2032 respectively.

TEP is also planning to retire, by 2032, Unit 3 of Sundt Generation Station ("Sundt"), which consists of a gas fired steam generator, and by 2027, five units of gas or oil combustion turbines located at Sundt and North Loop, that the company has for peaking capacity. The date for the retirement of the last plants mentioned, is based on plant depreciation, but will depend on the acquisition of replacement capacity as needed. UNSE is not anticipating the retirement of any of the power plants the company owns.

4. *Impacts on Emissions and Water Usage*

A.A.C. R14-2-703 requires that each load-serving entity provide detailed environmental impacts for each generating unit and power purchase contract. Environmental impacts include air emission quantities (in metric tons or pounds) and rates (in quantities per MWh) for regulated air pollutants, water consumption quantities and rates, and other standards subject to current or expected future environmental regulations. The code also requires the load-serving entity to provide descriptions of programs that mitigate or manage environmental impacts and the risks and uncertainties associated with environmental impacts. Environmental considerations are further discussed in Section V(G) of this report.

a) APS

APS's clean energy commitment includes the following:

- Provide 100 percent clean, carbon-free electricity by 2050.
- Achieve a resource mix that is 65 percent clean energy, with 45 percent of the generation portfolio coming from renewable energy by 2030.
- End all coal-fired generation by 2031.
- Requires advances in water conservation, emissions control, and waste management programs.

Water is used in power generation to cool down the steam cycle by removing waste heat, for power augmentation, emissions control, domestic purposes or to support chemical treatment processes. APS states that Arizona's water challenges are balanced between the increasing demand for water, due to high growth rates, and the limited supply of water, given the drought conditions of the state. APS states that the construction of PVNGS is an example of working to address the concerns with water usage in power generation. PVNGS is the first nuclear plant in the world that is not located adjacent to a large body of aboveground water. In addition, PVNGS uses reclaimed water from Palo Verde Water Reclamation Facility as its cooling water source. APS states that in 2019, 71 percent of all the water used by APS's generation fleet, was reclaimed water.

APS states it will make the following efforts toward water conservation over the planning period of 2020-2035:

- Retire or upgrade water-intense power plants: Four Corners plant will be retired in 2031.
- Cease coal generation in Cholla Unit 2 by 2025.

- Increase penetration of renewable energy resources that do not use water, like wind or solar.

- Implement DSM programs.

- Implement technological advancements in new power plants with efficient water-cooling strategies such as hybrid cooling systems.

- With these actions, APS expects the water usage to be decreased between 50 – 58 percent.

Also, between 2019 and 2035, the company's goal is to reduce the use of groundwater by 71 – 75 percent.

APS states that surveys of the conditions of the wells associated with APS power plants is routinely performed and the wells were evaluated for safety, degraded operational condition, and potential to allow aquifer cross-contamination or water-surface intrusion. As a result, 11 wells were abandoned in 2019, and another 41 wells were planned to be abandoned in 2020.

APS states the following actions are designed to minimize the impact of its operations to the environment:

- Installation of developed air pollution controls at Four Corners. As a direct result, the SO2 emissions in all APS-owned facilities from 2016, have decreased approximately 40 percent at the end of 2019.

- Replacement of older gas fired turbines with advanced ones, and modernized air pollution controls, as part of the Ocotillo Modernization Project. As a result, the energy generation capacity at the site was doubled, while the emissions of Nitric Oxide ("NOx") and Carbon Monoxide ("CO") were cut by more than half. Also, with this measure, the NOx emissions in all APS-owned facilities from 2016, were cut by approximately 56 percent at the end of 2019.

- Installation of upgraded combustion technology that increased the output from Redhawk Power Plant ("Redhawk") without increasing the emissions of nitrogen dioxide.

APS is also evaluating the installation of additional air pollution controls on two of its combined cycle units at the West PPP.

APS waste management practices involve maximizing the use of its fuels and supplies and minimizing or eliminating the waste that is generated by the company's processes. Some of the actions that the company has taken include:

- Disposal of the coal combustion residuals in ash ponds and dry storage areas at Cholla and Four Corners plants and selling a portion of its fly ash for reuse as a component in concrete production. APS plans to cease the combustion of coal at Cholla by mid-2025, and Four Corners by the end of 2031, which will have an impact in the reduction of coal combustion products.

- Recycle approximately 47 percent of the non-hazardous waste produced and generate between 88 and 97 percent less hazardous waste than the amount produced in 2001.

- APS identified a recycling company in the United States capable of handling and recycling the solar panels from its solar facilities, without generating any hazardous material.

- High-level nuclear waste (spent fuel) in PVNGS, is moved from the spent fuel pools to dry cask storage, until the U.S. Department of Energy can provide a permanent solution. Low-level nuclear waste is packaged in proper containers and shipped off-site for disposal.

b) TEP

TEP plans to provide more than 70 percent of its power from renewable resources by 2035. TEP's Preferred Portfolio includes the goal of reducing the use of water by 70 percent and producing 80 percent less CO2. TEP states that the carbon reductions target represents its efforts toward limiting warming below two degrees Celsius under the 2015 Paris Climate Agreement.

TEP states that while existing facilities in Arizona have already secured the legal rights to the water needed for their operation, there can be a conflict between the legal right to water and its physical availability. Furthermore, TEP believes one of the most effective ways to reduce power plant water use is by transitioning to a lower water use generating facility. The availability of surface water withdrawn in the case of the Four Corners or SJGS, is dependent on natural phenomena like precipitation and snow. TEP plans on the retirement of these facilities within the planning period, which will reduce significantly, and eventually eliminate any risk of water availability for power generation from surface waters.

TEP further states that the attainability of water withdrawn from groundwater aquifers is also dependent on the recharge of these aquifers and their hydrological characteristics and that this is the case for power plants like Springerville, Sundt, and Luna. TEP has implemented the following measures to reduce consumption of water:

- Springerville: TEP has an agreement with a local Native American Tribe, to limit the withdrawals of groundwater at the plant to 20,000 acre-feet annually. The cooling towers for Units 1 and 2, operate at high cycles of concentration, which reduces the amount of water used per unit of energy generated. In addition, the plant will start seasonal operations at the beginning of 2023, through the retirement of the units in 2027 and 2032.

- Wilson Sundt Generating Station: The facility consists of 10 natural gas fired RICE and two gas fired steam generators. The RICE generator replaced two 1950s vintage steam generators between 2019 and 2020, and with them, the use of water in the generating station was reduced by 70 percent.

- Luna: Supplements the groundwater withdrawals with treated municipal wastewater provided by the City of Deming, New Mexico. The water represents 12 percent of its total water consumption.

In November 2019, the University of Arizona Institute of the Environment ("UAIE"), issued the first phase of a study that assisted TEP in developing the relationship between the company's direct emissions of CO2 and the goal of limiting the rise of temperatures, consistent with the 2015 Paris Climate Agreement. The first phase of the study led to the adoption of the goal to reduce 80 percent of TEP's carbon emissions below 2005 levels by 2050. Phase two of the study used a methodology that identified the range of CO2 budgets based on a particular temperature target. All the portfolios that TEP developed for its 2020 IRP, achieve 30 percent emission reductions on average from 2020 to 2024.

The Environmental Protection Agency's ("EPA") Regional Haze Rule resulted in one of the environmental regulatory programs with an impact on TEP. It establishes a goal to reduce visibility impairment in several areas to natural conditions by 2064. In October 2018, the Arizona Department of Environmental Quality ("ADEQ") began a process to develop a control strategy for making progress toward this target for the period 2018-2028. As a result, ADEQ notified TEP that Sundt (Unit 3) and Springerville (Units 1 and 2) had been selected for potential emissions control analysis. The rule requires that this analysis considers the costs of compliance, the time necessary for compliance, the energy impact of compliance and the remaining useful life of the source subject to the analysis. TEP submitted its analysis for the three previous power plants in March 2020 and in June 2020 ADEQ agreed with its results.

TEP states that it is committed to reduce and eventually eliminate its dependency on coal-fired generation. Furthermore, TEP states that the acquisition of efficient and flexible natural gas resources allows it to cost-effectively replace the capacity of early coal retirements. Specifically, this involves a total of 468 MW that will be completed in 2022, with the retirement of 170 MW at SJGS. Also, as mentioned before, Springerville Units 1 and 2 will begin operating on seasonal basis starting in 2023, until its retirement between 2027 and 2031.

c) UNSE

Regarding the different portfolios presented by UNSE for the period between 2021 and 2035, there is a decrease in water consumption for all portfolios through 2028. This is due to the incremental use of renewable resources. After 2028, the use of water remains relatively constant, and increases in the later years for two portfolios as renewable capacity additions have been completed and the portfolios rely on existing assets.

NOx emissions also decrease through 2028, in all UNSE's portfolios, due to the increase of renewable energy in the resource mix. After this year, the emissions present an increase especially in two portfolios. In one of them, no renewable resources are added after that point. In the second portfolio, the rise of NOx emissions is due to the increase in the dispatch of the existing natural gas-fired resources as retail sales increase and the peak demand increases.

Chart 28 of UNSE's 2020 IRP presents the annual CO2 emissions for each portfolio analyzed. For each portfolio, CO2 emissions generally increase over time with the exception of P03aL1M1E1. Overall emissions are projected to peak in the 2025 – 2027 timeframe.

Chart 29 of UNSE's 2020 IRP, displays the annual NOx emissions for each portfolio that was analyzed. Since each portfolio increases the amount of renewable energy in UNSE's resource mix, there is a decrease in NOx emissions across portfolios through 2028, followed by an increase. TEP notes that portfolio P03a, although the lowest emitter of CO2, has the highest NOx emissions by the end of the planning period because existing natural gas-fired resources are increasingly dispatched as retail sales and peak demand increase.

Chart 30 of UNSE's 2020 IRP details the water consumption for each resource portfolio. Overall, water consumption is expected to decrease for all portfolios by the end of the planning period.

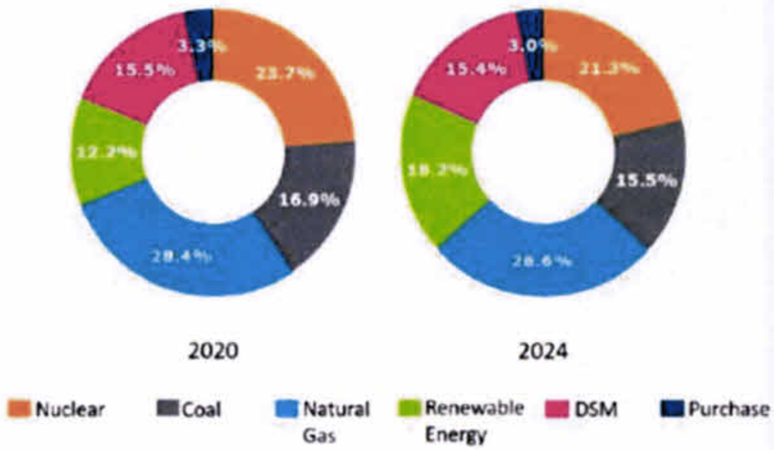
5. Summary of Action Plans

APS:

2020-2024 Additions	All Paths (MW)
DSM	575
Demand Response	193
Distributed Energy	408
Renewable Energy	962

Energy Storage	750
Merchant PPA/ Hydrogen-ready CT's	0
Microgrid	6
Total	**2,894**

FIGURE 7-4. 2020 & 2024 – ENERGY MIX



Source: APS's 2020 IRP, Page 136, Figure 7-4. 2020 & 2024 – Energy Mix

TEP:

TEP's Five-Year Action Plan states that it will complete the first phase of coal plant retirements when the Company's SJGS Unit 1 closes in June 2022. This retirement will bring the utility's total coal capacity retirement to 41 percent since 2015. TEP will finalize the build-out of planned solar and wind projects and will therefore double the renewable energy procurement for the utility. The utility will continue to satisfy EE compliance requirements by implementing cost-effective programs targeting 1.5 percent incremental energy savings over previous year's retail load throughout the five years.

UNSE:

Similar to TEP, UNSE will continue to target 1.5 percent incremental energy saving over the previous year's retail load throughout the Five-Year Action Plan. The Company also aims to implement cost-effective EE programs to reach this goal, as well as procure market-based resources to meet short-term capacity needs. This method is the least cost option capable of providing for the Company's summer capacity shortfalls. However, UNSE continues to explore more options.

IV. COMMENTS

A. Commissioner Comments

Commissioner Kennedy (March 5, 2019)

- Commissioner Kennedy stresses the importance of water conservation in the electricity generation process.

- Commissioner Kennedy asks for Arizona's regulated utilities to:

    1. Quantify the amount of water used for power generation.

    2. Quantify the amount of water used to generate electricity, used to pump water to the utility's power plants.

    3. Identify water sources used, and the sustainability of these.

    4. Identify the power plant's closure/phase-out dates.

    5. Describe the transition plan in place for the water resources currently being used in the power plants that are projected to close/phase-out.

    6. Identify any planned technological changes that would result in a material conservation of current water usage levels in the utility's plants.

AEPCO – Response to Commissioner Kennedy's Comments, (April 24, 2019)

- Quantify the amount of water used for power generation.

- The amount of water consumed per year by Apache Generating Station is shown below:

    - 2014 – 3,582 acre-feet
    - 2015 – 3,244 acre-feet
    - 2016 – 3,781 acre-feet
    - 2017 – 3,663 acre-feet
    - 2018 – 4,425 acre-feet

- AEPCO also owns and operates solar facilities, which utilize no measurable amount of water.

- Quantify the amount of water used to generate electricity, used to pump water to the utility's power plants

- In 2018, approximately 0.014 acre-feet of water were used to generate the power needed to run well-water pumps at Apache Station.

- Identify the water sources used, and the sustainability of these.

- The water used by Apache Station is pumped from underground wells located at or near the facility. In recent years, neighboring farms and irrigators have increased their withdrawal of local water, which may result in a sustainability issue for the supply. AEPCO is currently studying this issue.

- Identify the power plant's closure/phase-out dates.

- AEPCO has not identified retirement or closure dates for the Apache Station. Each unit in this plant has been assessed as viable and beneficial to AEPCO's members through at least 2035.

- Describe the transition plan in place for the water resources currently being used in the power plants that are projected to close/phase-out.

- When one or more units at the plant close, the water resources will be either cease to be pumped, or transition to supply other generating units.

- Identify any planned technological changes that would result in a material conservation of current water usage levels in the utility's plants.

- There are no planned technological changes, that would result in a reduction in water usage.

<u>APS – Response to Commissioner Kennedy's Comments, (April 30, 2019)</u>

- Quantify the amount of water used for power generation.

    - The total consumption of water per year, in the different APS generation plants is shown below:

    - 2016 – 101,915 acre-feet
    - 2017 – 107,568 acre-feet
    - 2018 – 106,068 acre-feet

- Quantify the amount of water used to generate electricity, used to pump water to the utility's power plants.

- The amount of water used to produce power used to pump water is negligible, estimated to be less than one percent of the total water consumed.

- Identify the water sources used, and the sustainability of these. APS uses three types of water for its nine owned/operated plants in the three-year average:

  - Treated effluent: considered a renewable water supply, APS consumed 72 percent of treated effluent.

  - Surface water: is considered renewable water, that comes from river, lakes and streams replenished by rainfall. APS consumed 13 percent of surface water. 98 percent of the surface water consumption by APS plants, is at the Four Corners, that withdraws water from the San Juan River ("SJR"). This consumption has been reduced by 30 percent in 2014, and in preparation of possible shortages on the SJR, APS is a partner in the San Juan Shortage Sharing Agreement.

  - Groundwater: it is considered a non-renewable water supply, since it can be withdrawn at rates that exceed the rate of recharge. 15 percent of APS total water consumption was groundwater. Reductions in groundwater consumption are achieved by retiring older water-intensive plants.

- Identify the Power Plant's closure/phase-out dates and describe the transition plan in place for the water resources currently being used in the power plants that are projected to close/phase-out.

- PVGS: Units 1, 2 and 3 have operating licenses through 2046, 2047 and 2048. Water supply contracts are in place with the Sub-regional Operation Group to provide water through 2050. Prior to the expiration of the existing operating licenses, PVGS may request a 20-year extension.

- Redhawk: Primary water-cooling supply is treated effluent from the Palo Verde Water Reclamation Facility. It also utilizes non-irrigation water from the Phoenix Active Management Area ("AMA") for drinking water and high-quality processes. There are no current plans to retire Redhawk. If retired, the groundwater rights would remain the property of APS and the cities could use or market the reclaimed water to others.

- Cholla: it relies upon percolating groundwater in the Coconino Aquifer. If the plant was fully retired, water would not be withdrawn from the aquifer.

Current plans for Cholla are to cease operations in 2025, but APS may consider conversion from coal to natural gas for one or more units.

- West PPP: it relies upon Phoenix AMA Non-irrigation water rights. There are no current plans to retire this plan.

- Ocotillo: it relies upon Phoenix AMA Non-irrigation water rights. There are no current plans to retire this plan.

- Sundance Power Plant: it relies upon Central Arizona Project ("CAP") Municipal and Industrial ("MI") Excess water. Due to the reduced availability of MI Excess water, APS contracted with the Gila River Indian Community for CAP Indian Priority water to be delivered through the Hohokam Irrigation District Canal. These contracts expire in December 2056.

- Saguaro Power Plant: it relies upon Tucson AMA Irrigation and Type II-Power water rights. There is currently no plan to retire these plants.

- Yucca: it relies upon percolating groundwater from the Yuma Groundwater Basin. If the plant was fully retired, water would not be withdrawn from the aquifer.

- Four Corners: it withdraws surface water from the SJR. The permit was owned by BHP Billiton ("BHP"), however, is currently transferred to APS and its partners.

- Identify any planned technological changes that would result in a material conservation of current water usage levels in the utility's plants.

- APS has retired two old steam units at the Ocotillo and replaced them with quick-start combustion turbines. The upgrade represents an 85 percent efficiency improvement.

<u>TEP – Response to Commissioner Kennedy's Comments, (April 30, 2019)</u>

- Quantify the amount of water used for power generation.

- The average annual water consumption for the period 2016-2018, was 19,118 acre-feet. By 2031, due to the planned retirement of certain generation plants, 40 percent reductions from current levels are expected.
- Quantify the amount of water used to generate electricity, used to pump water to the utility's Power Plants.

- Based on available data, the amount of water used to produce power used to pump water is negligible and estimated to be less than one percent of the total water consumption.

- Identify the water sources used, and the sustainability of these:

    - SGS: its source of water is the Regional C-Aquifer.

    - SJGS: its source of water is the SJR. Water consumption for this facility declined with the retirement of two units in 2017, and is expected to be even lower in 2022, when the facility ceases generation. In preparation of possible shortages on the SJR, APS is a partner in the San Juan Shortage Sharing Agreement.

    - Navajo Generation Station ("NGS"): its source of water is Lake Powell. Water withdrawal will be lower beginning 2019, when the facility ceases power generation.

    - Four Corners: the principal source of water is SJR. Water consumption declined approximately 30 percent with the retirements of some of its units in 2014. The use of water will decrease significantly in 2031, when the facility ceases power generation.

    - Sundt, North Loop, DeMoss Petrie: the principal source of water for these plants is local groundwater. The facilities are located within Arizona Department of Water Resources' ("ADWR") Tucson AMA, which requires that the amount of water removed, must be equal to the average replenishment rate of the aquifer.

    - Luna: its source is groundwater, supplemented with effluent from the City of Deming ("NM"). Water supply is assured for at least the next 50 years.

    - GRPS: its source of water is groundwater.

    - Valencia Power Plant ("Valencia"): its source of water is groundwater. The plant is located in the Santa Cruz AMA.

    - Black Mountain: its principal water source is groundwater provided by the City of Kingman.

- Identify the power plant's closure/phase-out dates.

    - SGS Units 1&2 – 2040, 2045

- SJGS Unit 1 – 2022
- Navajo – 2019
- Four Corners Units 4&5 – 2031
- Sundt Steam Units 1&2 – 2020
- Sundt Steam Units 3&4 – 2032, 2037
- Sundt Combustion Turbines – 2032
- North Loop 1-3, 4 – 2027, 2046
- DeMoss Petrie – 2046
- Luna – 2066
- GRPS Unit 3 – 2063
- Valencia 1-3, 4 – 2034, 2051
- Black Mountain – 2053

• Describe the transition plan in place for the water resources currently being used in the power plants that are projected to close/phase-out.

  - SGS: The source is the Regional C-Aquifer. TEP's rights to withdraw groundwater expire upon the cessation of power generation at the sire.

  - SJGS: The water rights are from a Grant of Authority from BHP Billiton. If water is not used, the water right reverts to BHP Billiton.

  - Navajo: Following its retirement, the water rights will revert to the State of Arizona.

  - Four Corners: BHP Billiton initially owned the permit, and it was transferred to the owners of Four Corners. Upon cessation of generation, the water rights will revert to BHP Billiton.

  - Sundt, North Loop, DeMoss Petrie: TEP's groundwater withdrawals rights can be moved within Tucson AMA for similar use.

  - Luna: upon cessation of power generation, a portion of the water rights remain with the facility, while the remaining rights will be returned to the State of New Mexico.

  - GRPS: The source of water is groundwater. Upon cessation of generation, the landowners would have the option of accessing groundwater.

  - Valencia: The source of water is groundwater provided by the City of Nogales. Upon cessation of generation, the facility would no longer receive water from the City.

- Black Mountain: The source of water is groundwater provided by the City of Kingman. Upon cessation of generation, the facility would no longer receive water from the City.

- Identify any planned technological changes that would result in a material conservation of current water usage levels in the utility's plants.

  - In 2016 and 2017, the company participated in projects to reduce water consumption and increase wastewater recycling at SGS.

  - TEP is retiring two old steam units at Sundt in 2020, and installing ten more efficient reciprocating engines, which result in a 70 percent reduction in water consumption.

Commissioner Burns (June 28, 2019)

- Commissioner Burns requests that the Load-Serving Entities Preliminary IRP, review and study the seven scenarios contained in his letter of June 7, 2019, in Docket No. RU-0000A-18-0284.

Commissioner Kennedy (February 19, 2021)

- Commissioner Kennedy requests the utilities to provide updated filings to the original IRPs.

- For the first update, the utilities are asked to file a Supplemental IRP with analysis of the following portfolios as soon as practicable or by March 14, 2021:

  - A portfolio in accordance with the Proposed Draft Energy Rules
  - The Optimal Resource Portfolio identified by Strategen.

- The second update should be a workplan detailing how each utility will modify the future IRP processes in accordance with the Draft PER requirements, specifically regarding stakeholder's engagement processes and the ASRFP process.

Commissioner Kennedy (February 25, 2021)

- Commissioner Kennedy requests the utilities to make a presentation on the IRP plans, for the workshop that will be held on March 15.
- The questions to be addressed by the utilities in the workshop are:

  1. Substantial changes that may have occurred since the initial filing of the IRPs.

2. The Supplemental IRP requested in Commissioner Kennedy's letter on February 19, 2021.

3. ASRFPs that may have been issued, bid upon, etc.

4. Load changes that may have occurred and their expected continuance.

5. Evolution of the electrification of transportation plans and how they inform the IRP's.

6. Updated analysis on near term action plans that implement the PER, including IRP changes.

- Commissioner Kennedy also requests some other questions, related to Resource Planning, to be addressed in the workshop.

Commissioner O'Connor (March 12, 2021)

- Commissioner O'Connor requests the utilities to address several questions during the workshop to be held on March 15, 2021.

Chairwoman Márquez Peterson (March 17, 2021)

- Chairwoman Márquez Peterson states that some issues arose during the March 15 Workshop, regarding the remainder of the Commission's process for evaluating the utilities' 2020 IRP.

- Chairwoman Márquez Peterson considers that Staff should hire a third-party consultant to conduct the necessary costs analyses, that will be then used by the Commission in its deliberations to make an inform decision.

- Chairwoman Márquez Peterson states that in March 2018, the Commission denied the utilities' 2017 IRPs and ordered them to include in them additional portfolios.

- Chairwoman Márquez Peterson affirms that the REST Modernization Docket is inextricably connected to the Energy Rules docket.

Commissioner Olson (March 17, 2021)

- Commissioner Olson agrees with Chairwoman Márquez Peterson that additional cost analyses must be performed, so that the Commission can properly evaluate the utilities IRPs.

- In addition, Commissioner Olson proposes the Commission require Staff to conduct a cost analysis of a "lowest cost" portfolio for APS and TEP. This portfolio would be the lowest cost mix of energy resources needed to meet the customers' energy needs.

Commissioner Kennedy (March 17, 2021)

- Commissioner Kennedy states that she received the letter from Chairwoman Márquez Peterson regarding IRPs and cost analyses with very few hours to respond. She also asks the Chairwoman why the regulated entities are given preferential treatment.

Commissioner Tovar (March 17, 2021)

- Commissioner Tovar responds to the letter from Chairwoman Márquez Peterson regarding IRPs and cost analyses and supports the Chairwoman's decision to put the item in the upcoming Staff Open Meeting.

- Commissioner Tovar states that the integrated resource planning is a process mandated in the current Commission rules, while the PER are a subject of a separate formal rulemaking proceeding.

- Commissioner Tovar expresses her understanding that Staff was ordered to retain a consultant to review the scenarios associated with the 2020 integrated resource plan, and not with the PER, and that changing the consultant's scope of work now, will only further delay the review of the 2020 IRPs.

Commissioner O'Connor (March 30, 2021)

- Commissioner O'Connor considers that since he proposed an amendment to the Draft Energy Rules, that if it passes, requires the utilities to create periodic cost analysis thru 2050, it is not in the public interest to have Staff prepare further cost analyses for the 2020 IRP Docket.

- Commissioner O'Connor recommends that the 2020 IRP is placed on an Open Meeting for vote regarding "acknowledgement" after Staff and Staff consultant IRP reports are received.
- Commissioner O'Connor expresses his interest in seeing the Draft Energy Rules on the April 2021 Open Meeting.

Commissioner Kennedy (April 20, 2021)

- Commissioner Kennedy states, in a letter to Director Abinah, that the IRP analysis is behind schedule and there are several questions that should be addressed before the Commission expands the current scope of work to be conducted by the third-party.

- Commissioner Kennedy lists the questions to be addressed.

Chairwoman Márquez Peterson (July 27, 2021)

- Chairwoman Márquez Peterson addresses in the letter some of the issues raised with respect to APS's resources and Purchased Power Agreements ("PPAs"), since the company filed its 2020 IRP.

- Chairwoman Márquez Peterson requests Ascend Analytics to address in its report the issue of APS's "must-run" assumptions on Four Corners and Solana Generating Station ("Solana").

- Chairwoman Márquez Peterson states that applying "must run" assumptions to the Four Corners and Solana resources may represent an approach that does not take into account all sources that can cost-effectively meet a utility's load forecast and could result in scenarios that do not represent the utility's "least-cost" portfolio.

- Chairwoman Márquez Peterson plans to ask Staff to address the issue of APS's 30-year Solana PPA with Solar One and whether the PPA's price at over four times the levelized cost of energy in 2020 and expected termination date of 2045, are consistent with the Commission's REST rules.

B. Stakeholder Comments – IRPs

Sierra – Response to APS Plan[8]

- Sierra Club states it was an active participant in the stakeholder process leading up to the development of APS's 2020 IRP and provided detailed comments earlier this year (2020) as part of the Preliminary-IRP process.

- Sierra Club stresses the importance of APS producing a robust and comprehensive 2020 IRP given the lack of a currently acknowledged IRP for APS.
- Sierra states that the APS 2020 IRP relies on unrealistically high load forecasts which deviate from historical trends of lower load growth.

- Sierra states that the IRP modeled limited scenarios and sensitivities, with three final portfolios with nearly identical short-term action plans and a misleading presentation of the "Accelerate" scenario and sensitivity analysis to make high adoption of renewables appear more expensive.

[8] October 15, 2020. https://docket.images.azcc.gov/E000009565.pdf

- Sierra states that APS does not appear to properly consider costs associated with water limitations required to operate and maintain the Four Corners, nor avoided costs of Effluent Limitation Guidelines compliance in the case of early retirement of Four Corners before the end of 2028.

- Sierra states that APS does not seriously evaluate closing Four Corners before 2031 in any of its final portfolios, including the cost of its coal contract, the value of its water rights, the step down in sustaining capital costs, the impact on market prices of locking in Four Corners production, and the value of a known retirement schedule for impacted communities to plan a just and equitable transition.

- Sierra states that APS forecasts EE investments significantly below levels achieved under the Commission's 2010 EE mandate, and below national average levels of EE investment as a percent of retail sales.

- Sierra states that APS makes renewable energy cost assumptions that are higher than average industry estimates, including unreasonably high renewable energy integration costs and failing to consider the accessibility of wind energy resources in New Mexico, especially any costs of transmission line build-out to do so.

- Sierra states that APS makes natural gas price assumptions that are low relative to industry standard estimates, which make long-term reliance on natural gas appear more favorable than otherwise for each of the three scenarios. Sierra Club also questions the framing of APS's natural gas combustion turbines as convertible to running on hydrogen, stating that this technology has not been proven.

- Sierra Club recommends that APS revise its IRP to include modeling the retirement of FCPP prior to 2031, update its load forecast to reflect more reasonable load growth assumptions, and test a more comprehensive set of sensitivities, particularly regarding gas prices.

- If APS does not revise its IRP in line with Sierra's recommendations, Sierra recommends the Commission decline to acknowledge APS's 2020 IRP, require APS to re-do its modeling to address Sierra's concerns, and require Commission approval for any new fossil resource acquisitions in the interim.

Sierra – Response to TEP Plan[9]

- Sierra states appreciation for the robust process established by TEP for its IRP.
- Sierra states that it participated in the TEP IRP advisory council and submitted comments earlier in 2020 as part of the Pre-IRP process.
- Sierra stresses the importance of TEP producing a robust and comprehensive 2020 IRP given the lack of a currently acknowledged IRP for TEP.
- Sierra praises the evaluation of an extensive number of portfolios (24), some of which consider early retirement or transition to seasonal operation at SGS, as well as TEP's update to its demand-side management assumptions and its recognition of the importance of early actions to reduce carbon emissions in order to minimize cumulative carbon emissions.
- Sierra states concern that the IRP fails to evaluate the impacts of COVID-19 on load forecasts.
- Sierra states concern that the IRP continues to rely on substantial fossil generation for the IRP period, despite creating exposure to ratepayers from risks associated with fuel price volatility and the potential for the fossil generation to become stranded assets with greater renewable energy adoption in the future.
- Sierra states that TEP did not utilize optimized capacity expansion modeling to identify optimal retirement dates for its coal fleet, and a more robust approach would include modeling of both utility-driven scenarios and stakeholder-driven scenarios in capacity expansion mode to allow for retirement of the Four Corners.
- Sierra states that TEP did not incorporate market participation in the CAISO EIM into its IRP modeling, and this should be studied and incorporated into future resource planning models.
- Sierra states that TEP uses a base case gas price forecast that is well below the U.S. Energy Information Administration Annual Energy Outlook's regional projections of delivered gas prices for the electric sector, which favors reliance on gas resources.
- Sierra states that TEP incorporates EV load projections as a flat, incremental load, and that this is a reasonable beginning assumption, but that the impact

[9] October 15, 2020. https://docket.images.azcc.gov/E000009564.pdf

of EV's on load and load peak should be studied and better integrated into future load forecasts.

- Sierra recommends that TEP submit a revised IRP that:
    - Tests an alternative natural gas forecast based on Wood Mackenzie's long-term natural gas price projections rather than its low-cost forecast,
    - Tests the costs or savings from imposing more aggressive emissions reductions targets, reducing reliance on generation from fossil resources,
    - Incorporates the impacts of COVID-19 on near-term load growth projections.
- Sierra further recommends that TEP develop a plan to incorporate entry into the EIM into its resource planning modeling.
- Sierra further recommends that TEP conduct a detailed study of the economics of continuing to operate SGS and Four Corners, based on optimized capacity expansion software and including the impact on market prices of coal plant retirements and subsequent effects on renewable resource economics.
- Sierra further recommends that TEP study the impacts of EV load on peak demand and energy, including refining its understanding of its own EV load, evaluating how EV load can be incorporated with time-of-use pricing or other mechanisms to reduce peak impacts from EV load, and evaluating the impact of vehicle-to-grid technologies.
- Sierra recommends that the Commission conditionally acknowledge TEP's IRP based on the Company's commitment to follow Sierra's recommendations above and its commitment to aggressively ramp up its emissions reductions in the near term.

TEP Response to Sierra Club's Comments[10]

- Regarding COVID-19 impacts on load forecast, TEP states that the first stay-at-home orders were issued in mid-March, only three months before the TEP IRP was due, and that there were no models at the time that could have produced reliable forecasts under pandemic conditions. TEP further states that some of its alternative load scenarios could reasonably be expected to include the effects of the pandemic on electricity demand, and

[10] November 16, 2020. https://docket.images.azcc.gov/E000010125.pdf

that its preferred scenario is no more sensitive to load uncertainties than other portfolios considered under a stochastic risk analysis.

- Regarding TEP's continued reliance on fossil generation resources and fuel price and stranded asset risks to ratepayers, TEP states that in its 2020 IRP it determined that its natural gas resources will provide essential capacity, flexibility, and reliability as TEP transitions to a renewable-based portfolio, and that their share of meeting TEP customer energy needs will decrease over time. TEP further states that its natural gas resources can produce power at levels far below their rated capacities, which will allow TEP to ramp down natural gas resources and accelerate renewable energy adoption if natural gas prices exceed the ranges in TEP's risk analysis. TEP further states that widespread adoption of renewable energy throughout the U.S. will likely continue to exert downward pressure on natural gas prices, as they compete with each other, and that TEP mitigates natural gas price risk through its hedging policies.

- Regarding whether TEP should revise its 2020 IRP with higher natural gas price assumptions, TEP states that TEP has access to natural gas sourced from the Permian and SJGS basins which have been some of the lowest priced natural gas in the U.S. in recent years, while Sierra Club's price forecast is based on eight different basins throughout the west. TEP further states that it subjected its preferred scenario and several others to sensitivity and stochastic risk analyses with alternative gas price trajectories exceeding \$5.00/MMBTU by 2035, and therefore believes it is unnecessary to refile its IRP on the basis of its natural gas price forecast assumptions.

- Regarding the need to study the load impact of EV's, TEP states that it considered EV load impacts on peak demand because EV charging is included in the sales forecast of its IRP and therefore contributes to the growth in forecasted peak demand. TEP also states that whether current EV charging contributes more or less to peak demand than other electricity end uses is uncertain given that most charging occurs in locations without separate sub-meters for EV charging.

Interwest Energy Alliance ("Interwest") – Response to APS Plan[11]

- Interwest states that it is a 501(c)6 nonprofit trade association of renewable energy project developers and equipment manufacturers and that it has been actively engaged in public input processes and regulatory dockets related to APS's resource planning and its acquisitions of renewable energy.
- Interwest states that it supports APS's 2020 IRP and asks the ACC to consider its recommendations for future opportunities to improve the usefulness of the IRP to stakeholders and ratepayers in Arizona.

[11] October 15, 2020. https://docket.images.azcc.gov/E000009563.pdf

- Interwest praises APS's commitment to a clean energy transition.
- Interwest recommends that APS implement the following to strengthen its action plan and future IRPS by adding additional value to renewable resources:
    - APS should move toward 100 percent clean energy regardless of whether the Commission adopts a clean energy mandate.
    - APS should continue to evaluate cost declines of solar, wind and storage, and should model additional geographic resource diversity to achieve capacity and reliability needs.
    - APS should reconsider its fossil fuel generation in relation to renewable resources to ensure its methodologies reflect least-cost integration principles and avoid undue discrimination in relation to thermal generators.
    - APS should continue to consider opportunities for market participation in a Regional Transmission Organizations ("RTO") as it studies transmission buildouts and energy flows to save consumers money while enhancing system reliability.

Western Resource Advocates ("WRA") – Response to APS and TEP Plans[12]

TEP:

- WRA states that it participated in TEP's IRP Advisory Council, including participation in regular meetings, providing feedback on components of the IRP, proposing scenarios to be modeled as possible portfolios of the IRP, and providing oral comments to TEP at its IRP public meeting in May 2020.
- WRA states that of the 24 portfolios that TEP modeled and presented to stakeholders, WRA initially preferred portfolios 02, 08, 09, and 16, but that it now supports TEP's preferred portfolio 17.
- WRA states that the TEP 2020 IRP is the result of over a year of stakeholder engagement and is the most significant commitment to clean energy transition in Arizona.
- WRA further states that while TEP has not made a 2050 announcement, their IRP states that the 2035 announcement is a "key milestone in [its] journey to rapidly and responsibly transition to 100 percent clean energy resources."

[12] October 15, 2020. https://docket.images.azcc.gov/E000009559.pdf

- WRA encourages the Commission to acknowledge the TEP 2020 IRP.

- WRA also encourages the Commission to continue to monitor TEP's efforts to support a just and equitable transition for communities impacted by coal plant closures to ensure the situation with Navajo Generating Station is not repeated.

APS:

- WRA states that it participated in a small stakeholder group that APS convened regarding their 2020 IRP, including regular meetings from late 2018 through 2019, that it reviewed the E3 modeling that APS previously presented to the Commission, that it participated in all of APS's public IRP meetings, and that it participated in meetings surrounding the development of APS's goal to procure 100 percent clean energy by 2050, 65 percent clean energy by 2030, 45 percent renewable energy by 2030, and an exit from coal by 2031.

- WRA states that the portfolios presented in APS's final 2020 IRP are consistent with this clean energy goal.

- WRA states that the APS 2020 IRP includes three portfolios, but not a preferred portfolio, and that all three portfolios call for the same resources within the near-term Action Plan window and have the same Action Plan.
- WRA notes that APS states that their Action Plan maintains flexibility in how it will select clean energy to best serve its customers.

- WRA states that plans to build gas plants in the "Bridge" portfolio raises some concerns that such investments run risks of accumulating stranded assets that may result in customers paying for plants that are no longer economic. WRA notes that APS appears to try and mitigate this concern by labeling such natural gas plants as "hydrogen ready," but questions what APS means by this term and the economics of the distinction and recommends that further discussion and consideration is advisable.

- WRA states that APS's Discussion of Results section reads as if it prefers Bridge and goes on to compare the other portfolios to Bridge, while Bridge includes the addition of new gas plants and the smallest reduction in carbon emissions and water usage.

- WRA recommends the Accelerate portfolio, and states that the Bridge portfolio carries extra risk both in regard to cost and the environment.

- WRA encourages the Commission to acknowledge the APS 2020 IRP and encourages APS to move aggressively to reduce carbon.

- WRA also encourages APS to consider a focus on just and equitable transitions for impacted communities in future IRPs and in other forums and stakeholder processes and encourages the Commission to continue to monitor these transition efforts.

TEP Response to WRA[13]

- TEP acknowledges WRA's final IRP comments which are supportive of TEP's planned clean energy transition and of Commission acknowledgement of the TEP 2020 IRP.

Institute for Policy Integrity ("Institute") – Response to APS, TEP, UNS and AEPCO Plans[14]

- The Institute states that it is a nonpartisan think tank dedicated to improving the quality of government decision-making and regularly advises on state electricity policy, in particular on whether and how to monetize the effects of air pollutant emissions caused by electricity generation.

- The Institute encourages the Commission to ask that each LSE include in its IRP not only information about the quantities of air pollutants the LSE expects to emit but also monetized estimates of the damages expected to result from those emissions.

- The Institute states that monetizing emissions impacts is compatible with Arizona IRP requirements, in that Arizona regulations require IRPs to:

    - Take into consideration the environmental impacts, including air pollution quantities and rates for several specific air pollutants for each generating unit represented in the proposed portfolios, according to A.A.C. § R14-2-703(B)(1)(p).

    - Address the adverse environmental impacts of power production, according to A.A.C. § R14-2-703(F)(3).

    - Include a plan for reducing environmental impacts related to air emissions, according to A.A.C. § R14-2-703(D)(17).

    - Include expected reductions in environmental impacts from demand management programs, according to A.A.C. § R14-2-703(D)(14)(d).

[13] November 13, 2020. https://docket.images.azcc.gov/E000010103.pdf

[14] October 15, 2020. https://docket.images.azcc.gov/E000009545.pdf

- o Effectively manage the uncertainty and risks associated with costs and environmental impacts, according to A.A.C. § R14-2-803(F)(7).

- o Include the cost analyses and projections, including the cost of compliance with existing and expected environmental regulations, according to A.A.C. § R14-2-703(D)(1)(h).

- The Institute states that no LSE currently reports monetized estimates of the damages done by their emissions, even though A.A.C. § R14-2-703(I) invites LSEs to provide the ACC with analyses "pertaining to environmental impacts which may include monetized estimates of environmental impacts that are not included as costs for compliance."

- The Institute states if LSEs took a more comprehensive approach to reporting on the costs of both compliance and damages, this would help the ACC, stakeholders, and the public to understand the benefits and costs of LSE IRPs, and it would help LSEs to better address the adverse environmental impacts of power production as required by Arizona law.

- The Institute states that A.A.C. § R14-2-704(B)'s requirement that each LSE's IRP be "reasonable and in the public interest" is relevant, since §§ 704(B)(7)-(9) state that "environmental impacts of resource choices and alternatives," "the degree to which the [LSEs] consider all relevant resources, risks, and uncertainties," and "the degree to which the [LSE]'s plan for future resources is in the best interest of its customers" are all factors to consider in making the reasonableness determination.

- The Institute states that monetizing emissions impacts would serve Arizona ratepayers in several ways, by facilitating comparison of important costs and benefits, and by revealing important additional information about costs and benefits.

- The Institute states that there are readily available tools and techniques for monetizing emissions, including those employed by the Interagency Working Group's Social Cost of Carbon tool and various existing public health models.

<u>Diné CARE, Tó Nizhóni Ání, and Black Mesa Trust (the "NGOs") – Response to APS Plan</u>[15]

- The NGOs state that they submitted comments in the previous APS resource planning proceeding in 2018 (Docket No. E-00000V-15-0094).

[15] October 16, 2020. https://docket.images.azcc.gov/E000009579.pdf

- The NGOs state that they acknowledge and praise the important steps APS has taken to transform itself from a dramatic over-reliance on coal and natural gas to a commitment to de-carbonize its generation portfolio over the coming years.

- The NGOs also state that the APS 2020 IRP leaves a number of critical issues unaddressed relating to the long-term prosperity and well-being of the Navajo Nation, the Hopi Tribe, and coal-impacted communities.

- The NGOs recommend that the Commission take steps to improve the APS 2020 IRP in ways that provide advantages for both tribes while still benefitting APS customers and shareholders.

- The NGOs state that the APS 2020 IRP contains four main deficiencies:

  - The IRP contains a minimal suite of portfolios, which limit the possibilities for tribal clean energy development to be part of its resource planning.

  - The IRP contain continued presence of gas, which short-changes potential tribal clean energy development.

  - The IRP continues to operate the Four Corners until 2031, when the Institute for Energy Economics and Financial Analysis testimony in the APS rate case (Docket No. E-01345A-19-0236) indicates that the Four Corners plant will not remain economically viable until 2031. The NGOs state that this is a failure by APS to recognize economic realities and does a disservice to the communities that will have to plan around its closure.

  - The IRP uses inaccurate renewable energy cost assumptions, creating scenarios where the status quo appears more economically appealing than accelerating the transition to clean energy through tribal clean energy development opportunities.

- The NGOs recommend that the APS IRP should reflect a long-term commitment to developing clean energy projects that replace any retired coal capacity with an equal proportion – one-to-one per MW of peak ownership – of tribal wind, solar, and storage projects. The NGOs state that this means the Commission should require APS to commit to adding at least 2,097 MW (1,145 MW for Four Corners, 337 MW for Navajo, and 616 MW for Cholla) of new tribal clean energy resources to its system over time as part of its long-term resource acquisition planning.

- The NGOs state that several successful clean energy project installations on lands near Kayenta, and of the Moapa Band of Paiutes and the Jicarilla

Apache Nation, as well as ongoing development discussions between the Navajo Nation, Hopi Tribe, and the Los Angeles Department of Water ("LADW") and Power, all suggest the viability of similar partnerships between APS and the Navajo Nation and Hopi Tribe.

- The NGOs state that according to consulting firm Lazard's latest analysis in 2019, the levelized cost of energy from utility-scale PV technologies is now far below the cost of coal-fired generation and even out-competes new-build gas generation.

- The NGOs state that Arizona's neighbors are setting an embarrassingly high bar in comparison to APS's lack of commitments to tribal clean energy procurement. The NGOs state that the Energy Transition Act in New Mexico carved out $40 million dedicated specifically to assisting communities in the Four Corners region in the transition of the planned closure of SJGS, and Public Service of New Mexico approved a package of four replacement power projects that will be built in communities near the plant.

<u>APS Response to Diné CARE, Tó Nizhóni Ání, and Black Mesa Trust (the "NGOs") Comments</u>[16]

- APS states that it is committed to assisting Navajo and Hopi communities to address concerns about the economic impact of the transition away from coal. APS states that its discussions with the Navajo Nation, Hopi Tribe, and surrounding communities have resulted in the APS Coal Community Transition Plan ("CCTP"), which includes:

  - A commitment by APS to provide $129 million in customer and shareholder funding to the Navajo Nation over ten plus years for development assistance targeting economic diversification, renewable energy, transmission support, electrification of homes and businesses within the Nation, and redeployment of employees.

  - A commitment by APS to provide $12 million to Cholla Power Plant communities over five years as well as job redeployment offers to all APS employees at Cholla.

  - A commitment by APS to provide $3.7 million to the Hopi Tribe over five years in consideration of APS's ownership in Navajo and its reliance on a mine located within the Hopi Reservation.

[16] November 13, 2020. https://docket.images.azcc.gov/E000010103.pdf

- APS states that if the Commission approves the CCTP, it will go a long way in resolving the issues raised by the Navajo Nation, Hopi Tribe, and surrounding communities in this docket.

Diné CARE, Tó Nizhóni Ání, and Black Mesa Trust (the "NGOs") – Response to TEP Plan[17]

- The NGOs state that they submitted comments in previous TEP resource planning proceedings (Docket No. E-01933A-19-0028).

- The NGOs state that they acknowledge and praise the important steps TEP has taken to transition to clean energy.

- The NGOs also state that the TEP 2020 IRP leaves a number of critical issues unaddressed relating to the long-term prosperity and well-being of the Navajo Nation, the Hopi Tribe, and coal-impacted communities.

- The NGOs recommend that the Commission take steps to improve the TEP 2020 IRP in ways that provide advantages for both tribes while still benefitting TEP customers and shareholders.

- The NGOs state that the TEP 2020 IRP contains two main deficiencies:

    - The IRP continues to rely on new gas capacity, which short-changes potential tribal clean energy development.

    - The IRP assumes an unrealistic life extension for coal when the Institute for Energy Economics and Financial Analysis testimony in the APS rate case (Docket No. E-01345A-19-0236) indicates that the Four Corners will not remain economically viable until 2031. The NGOs state that this is a failure by TEP to recognize economic realities of the costs of keeping Four Corners running and does a disservice to the communities that will have to plan around its closure.

- The NGOs recommend that the APS IRP should reflect a long-term commitment to developing clean energy projects that replace any retired coal capacity with an equal proportion – one-to-one per MW of peak ownership – of tribal wind, solar, and storage projects. The NGOs state that this means the Commission should require TEP to commit to adding at least 664 MW (114 MW for Four Corners, 181 MW for Navajo, and 369 MW for SJGS) of new tribal clean energy resources to its system over time as part of its long-term resource acquisition planning.

[17] October 16, 2020. https://docket.images.azcc.gov/E000009579.pdf

- The NGOs state that several successful clean energy project installations on lands near Kayenta, and of the Moapa Band of Paiutes and the Jicarilla Apache Nation, as well as ongoing development discussions between the Navajo Nation, Hopi Tribe, and the LADW and Power, all suggest the viability of similar partnerships between TEP and the Navajo Nation and Hopi Tribe.

- The NGOs state that according to consulting firm Lazard's latest analysis in 2019, the levelized cost of energy from utility-scale PV technologies is now far below the cost of coal-fired generation and even out-competes new-build gas generation.

- The NGOs state that Arizona's neighbors are setting an embarrassingly high bar in comparison to TEP's lack of commitments to tribal clean energy procurement. The NGOs state that the Energy Transition Act in New Mexico carved out $40 million dedicated specifically to assisting communities in the Four Corners region in the transition of the planned closure of SJGS, and Public Service of New Mexico approved a package of four replacement power projects that will be built in communities near the plant.

<u>TEP Response to NGOs Trust Comments</u>[18]

- TEP states that the Commission's PER require utilities to "give preferential treatment to Renewable and Clean Energy Resources sited or deployed in Impacted Communities, according to § R14-2-2708(C)(3) of the proposed rules, Docket No. RU-00000A-18-0284. TEP states that it supports these requirements and is committed to aligning its long-term resource planning efforts with the Navajo Nation and Hopi Tribe to support the transition away from coal to clean energy resources.

- TEP states that it intends to issue a set of ASRFPs within the next 24 months to seek to acquire several hundred MW of new renewable and energy storage capacity and is committed to work with tribal organizations to site a portion of this new clean energy capacity on or near tribal communities impacted by early coal plant retirements, subject to available transmission and timing of future IRPs.

- TEP states that it also will seek by 2032, to acquire additional clean energy capacity sited within or deployed near tribal communities impacted by the closure of the Four Corners, subject to available transmission and timing of future IRPs.

[18] November 16, 2020. https://docket.images.azcc.gov/E000010125.pdf

Southwest Energy Efficiency Project ("SWEEP") – Response to TEP Plan[19]

- SWEEP states that it commissioned the services of Strategen Consulting ("Strategen") to conduct an independent analysis of TEP's 2020 IRP as part of its review of the IRP and its participation in TEP's IRP Advisory Council. SWEEP states that the Strategen analysis utilized capacity expansion modeling to identify which portfolios are least cost and should be utilized to meet TEP's electricity demand over the next 15 years.

- SWEEP states that based on the Strategen modeling results, it recommends that the Commission direct TEP to:

  - Eliminate coal unit "must run" designations for future resource planning and modeling,

  - Remove modeling restrictions that limit the amount of EE that can be selected as a resource option,

  - Remove modeling restrictions to allow the economic cycling and economic retirement of coal units,

  - Implement the economic cycling and economic retirement of coal, including seasonal operations, and

  - Achieve 40 percent cumulative energy savings by 2030 from a broad portfolio of EE measures.

- SWEEP states that the modeling results indicate that if TEP implements both economic cycling of coal and 40 percent EE by 2030, it could reduce TEP's NPVRR by $286 million.

TEP Response to SWEEP's Comments[20]

- TEP states that its coal units are designated must-run resources due to the non-cycling operating characteristics of large steam units and the contractual must-take coal obligations within its current coal supply agreements. TEP further states that it would be subject to take-or-pay penalties if it were to burn less than a minimum quantity of coal each year, and that its SJGS and Four Corners coal units are dispatched economically to achieve the minimum coal take requirements under these agreements. TEP states that it plans to enter into future coal supply agreements that reduce the must-take obligations of SGS in line with its seasonal operation plans and planned unit retirements.

[19] October 16, 2020. https://docket.images.azcc.gov/E000009567.pdf
[20] November 16, 2020. https://docket.images.azcc.gov/E000010125.pdf

- TEP states that SWEEP's preferred portfolio recommendations that TEP reduce its coal generation production by 80 percent starting in 2021, and only dispatch TEP's coal units during the months of June through August or on an emergency basis, would not be practical from a workforce logistics standpoint for both the SGS and the El Segundo mine. TEP further states that the cost of take-or-pay penalties and replacement power would result in higher costs to customers.

- TEP states that California's over-reliance on capacity imports from other states was a contributing factor to its rolling blackouts in August 2020, and closure of TEP's SGS and Four Corners units would reduce its capacity by 2,300 MW. TEP states that capacity shortages will continue to be problematic until more firm resource capacity is built to cover peak regional demands.

- TEP states that its IRP modeling did not contain any restrictions limiting the amount of EE that can be selected. TEP states that it considered the costs and benefits of scenarios with a range of EE savings, including emission and demand reduction benefits, the ability to implement the underlying measures, and the effects of federal regulations on TEP's ability to claim credit for energy savings. TEP states that based on these considerations, it determined that its preferred portfolio should include 1,900 GWh of cumulative savings by 2035, beyond those required by existing Commission requirements.

- TEP states that while SWEEP recommends targeting a 40 percent cumulative energy savings goal by 2030, TEP agreed to a demand side resource standard as part of the new Energy Rules which would require demand side resource capacity equal to 35 percent of TEP's 2020 peak demand by January 1, 2030. TEP states that it also supports continuation of certain measures not included in SWEEP's analysis, such as the Low-Income Weatherization Program.

SWEEP and Sierra – Response to APS Plan[21]

- SWEEP and Sierra state that they plan to submit at a future date a complete capacity expansion model that determines the least cost portfolio of resources to reliably meet electricity demand over the next 15 years, and various portfolios that evaluate the economic cycling of coal units and determine the level of demand-side resources that can reliably meet customer electricity needs.

[21] October 16, 2020. https://docket.images.azcc.gov/E000009566.pdf

APS Response to Sierra and Interwest[22]

- APS states that there are significant reliability and affordability challenges to closing the Four Corners in the near term, especially noting the capacity shortages in the western market demonstrated by the rolling blackouts experienced during summer of 2020, and that Four Corners is valuable to APS customers and the APS system in this regard.

- APS states that it worked with an outside consultant to develop its cost to integrate variable energy resources, and that it remains open to working with stakeholders on approaches that address integration costs and welcome stakeholder dialogue, studies, and supporting information, similar to information received during the IRP stakeholder workshops.

C. Stakeholder Comments – Ascend Team Report

Abhay Padgaonkar[23]

- Mr. Padgaonkar states that the Ascend analysis has ten fatal flaws, including at least three violations of Decision No. 76632:
  - A "bogus growth assumption" of 2.8 percent annual growth rate in base peak demand, whereas actual annual growth rate since 2005 has been 0.6 percent.
  - A lack of independent review as required by Decision No. 76632, since all modeling and analysis was performed by the utilities themselves and not by Ascend Analytics.
  - A lack of review of both costs and benefits of IRP portfolios and scenarios as required by Decision No. 76632, since the Ascend report includes costs, but not benefits of scenarios, especially including emissions reduction benefits in terms of reduced damages.
  - A failure to consider potential early retirement of Four Corners.
  - An acknowledgement by the Ascend report that a more thorough independent study may be needed to support regulatory policy making.
  - A note that either APS's modeling software or its use of that software in its IRP analysis contained a critical flaw.
  - Flawed assumptions based on using utilities' flawed IRP portfolios as a starting point and assuming natural gas generation would

[22] November 13, 2020. https://docket.images.azcc.gov/E000010103.pdf
[23] August 18, 2021. https://docket.images.azcc.gov/E000015189.pdf

remain a primary resource for incremental capacity in a least-cost portfolio.

- Lack of questioning about the prudency and must-take nature of the Solana solar PPA contract by APS.

- A recommendation for a stakeholder engagement process, when APS did not act sufficiently based on the stakeholder input it received.

- Presentation of a "least-cost portfolio" within the Ascend report at the same time as the report also states that a full capacity expansion analysis would be necessary to identify a least-cost portfolio.

Arizona Public Interest Research Group Education Fund ("PIRG") [24]

- PIRG states that it is concerned Ascend did not provide an independent analysis, since all modeling was performed in the utilities' modeling software by the utilities themselves rather than by Ascend Analytics, and that a top recommendation of the report is for the Commission to commission a study using an independent analytical firm.

- PIRG states that the Ascend report raises more questions than answers, including 26 sets of questions PIRG has regarding various assumptions and approaches to the Ascend analysis.

- PIRG states that the lack of necessary independence and data in the Ascend report wastes Commission and Staff time and dollars, with a financial impact to Arizonans, since the Ascend contract and analysis took time and budget to accomplish.

WRA[25]

- WRA states that it has identified significant deficiencies with the Ascend report, that it was required to be completed too quickly with too many constraints and cannot be relied upon for long-term planning purposes.

- WRA states that the report's projection of costs out to 2040, is highly speculative, and that Ascend itself states "cost estimates beyond 2030, are very speculative and should be taken as rough estimates."

- WRA states that the report only looks at costs and not at benefits from decarbonization portfolios, that a Strategen analysis on behalf of SWEEP

[24] August 18, 2021. https://docket.images.azcc.gov/E000015186.pdf
[25] September 3, 2021. https://docket.images.azcc.gov/E000015488.pdf

shows potential benefits of 100 percent carbon free energy of up to $2 billion for Arizona, and that avoided costs of climate change such as the social cost of carbon (estimated by the Biden Administration to be $51 per ton in March of 2021) could have been included.

- WRA states that the Ascend report's least-cost portfolio is also a high-risk portfolio, because it could create expensive stranded assets in the form of natural gas plants. WRA further notes a lack of capacity expansion modeling in the Ascend analysis, such that the report's least cost scenario may not actually be the least cost scenario.

- WRA states there are also additional modeling concerns with the Ascend analysis, including:

    - A higher assumed levelized cost of solar and wind resources than typical power purchase agreement prices available in the region, which are in the low $20s per MWh, in addition to potential extensions of the investment tax credit for renewable energy resources.

    - No sensitivity to market prices.

    - Lack of adequate modeling of high levels of renewable resources due to limitations in the modeling software used by APS.

    - A fixed assumption that Four Corners would remain part of the APS fleet until 2031, with no alternative retirement scenarios evaluated.

    - The use of hourly production cost models instead of five-minute data, which would better illustrate the value of flexible resources such as batteries.

- WRA states that the actions recommended by Ascend for the Commission to take in order to obtain adequate information for decision-making need not stand in the way of finalizing the pending IRPs or other related dockets, but rather they are important considerations for future IRPs.

- WRA recommends including not only costs of implementation, but also considerations of avoided costs along with other benefits, both direct and indirect, to obtain a true cost-benefit analysis.

- WRA states that the long-term cost assumptions of the Ascend study are highly speculative, but the near-term numbers are reliable and show only modest, negligible increases in energy costs for Arizona while providing substantial economic, environmental, and reliability benefits.

- WRA states that it continues to recommend that the Commission move forward with acknowledging the 2020 IRPs.

Interwest[26]

- Interwest states that it wishes to reaffirm its support of the APS 2020 IRP.

- Interwest states that the Ascend report provides interesting information that could inform a broader discussion, but it should be "taken…with a grain of salt," as described in the report's own words.

- Interwest states that the Ascend study compares portfolios which were not optimized and that it was performed deterministically rather than stochastically such that countless options and variables were not considered or captured accurately, including the ability of flexible resources to participate in existing or future wholesale markets.

- Interwest states that it supports the eight recommendations Ascend outlined in its report for further analysis to provide additional information to the Commission.

- Interwest states that it suggests that any comparison between portfolios be made in accordance with Arizona statutes that require an analysis of risk, including economic and environmental impacts, to be included in each biennial integrated resource plan, according to A.A.C. § R14-2-703(E).

- Interwest states that it would be more helpful to compare realistic portfolios that fulfill requirements of Arizona law rather than using a hypothetical least-cost portfolio which does not comply with Arizona law as a baseline for comparison.

Terry Finefrock, Critical Infrastructure Investments[27]

- Mr. Finefrock states that the Ascend report is not independent nor comprehensive, since it does not comprehensively value internal and external costs and benefits.

- Mr. Finefrock states that the report does not identify the optimal system component configuration required to provide the lowest total cost, reliable and resilient electric system.

- Mr. Finefrock states that Ascend utilized utility modeling tools that are naturally biased to optimize shareholder values rather than ratepayer values.

[26] September 21, 2021. https://docket.images.azcc.gov/E000015788.pdf

[27] September 22, 2021. https://docket.images.azcc.gov/0000204782.pdf

- Mr. Finefrock states that this modeling did not consider a range of avoidable costs, energy storage benefits, reduced water use benefits, environmental benefits from reduced greenhouse gas emissions, benefits of substation energy storage, ratepayer-community benefits of expanded aggregated net metering, and flexible retirement of solar generation in smaller increments than conventional goal-gas power plants.

- Mr. Finefrock recommends development of an ACC designed and controlled system simulation/modeling tool to provide greater independent oversight over utility resource planning and reduced frequency of contentious, costly, repetitive administrative proceedings.

- Mr. Finefrock recommends expansion of aggregated net metering to allow residential customers, small businesses, apartments, and others to aggregate their demand and procure solar facilities and power purchase agreements.

Brad Johns[28]

- Mr. Johns states he is concerned that the cost of moving to 100 percent renewable energy is very high.

- Mr. Johns notes the discrepancy between TEP and Ascend in estimated costs of achieving 80 percent emissions reductions by 2040, where TEP estimates costs of $18 million and Ascend estimates $199 million.

- Mr. Johns states that if the costs are more like TEP's estimate, then moving to 80 percent or 100 percent renewables in 2050 appears feasible, but if Ascends cost estimates are more accurate, then postponing the renewable goals to a later date is the preferred alternative.

- Mr. Johns states that it is important to determine if the cost drivers are more like TEP's or Ascends assumptions.

Arizona Technology Council ("ATC") and Ceres[29]

- ATC and Ceres state that the Energy Futures Group ("EFG") is a nationally renowned consultancy with deep expertise in energy planning and analysis.

- ATC and Ceres state that EFG conducted an independent assessment of the Ascend Analytics report and concluded that the Ascend report and underlying utility modeling had significant shortcomings, inconsistencies, and a lack of transparency, and failed to achieve its objective.

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[28] September 24, 2021. https://docket.images.azcc.gov/E000015843.pdf
[29] October 19, 2021. https://docket.images.azcc.gov/E000016215.pdf

- ATC and Ceres attached a copy of what they state is the EFG report on its independent assessment of the Ascend Analytics report.

- The EFG report states five main factors in the Ascend report that contribute to an incorrect and overstated estimate of APS's costs to comply with the Clean Energy Rules:

  - Flaws with APS's modeling that cause its costs of clean energy to be incorrect and generally overstated.

  - Cost and constraint limitations in APS's underlying modeling that make it unlikely for APS's least cost portfolio to represent the utility's true least cost portfolio.

  - Gas prices that were too low in the near term, causing Ascends least cost portfolio to be one in which natural gas generation remained the primary resource for incremental capacity.

  - Limitations in the modeling platform that resulted in an effectively handpicked resource mix rather than an optimized one.

  - Failure to evaluate economic retirement or dispatch of the Four Corners coal plant.

- The EFG report states the differential between TEP's and Ascends extrapolations of its costs of compliance with the Clean Energy Rules is largely attributable to differences of opinion between TEP and Ascend about the Effective Load Carrying Capability ("ELCC") of renewables and storage.

- The EFG report states that Ascend does not provide any of the specific ELCC values it believes TEP ought to have used, and this lack of transparency prevents full understanding of the significance of the difference of opinion.

- The EFG report states that the difference between Ascend and UNSE projected cost impacts is due to an error Ascend made in its directed treatment of EE.

V. ANALYSIS OF IRPS

Pursuant to A.A.C. R14-2-704(A), Staff has reviewed the filings made under A.A.C. R14-2-703(C), (D), (E), (F), and (H) (the IRPs) for compliance with the requirements of Decision Nos. 73884, 75068, and 76632, and the 11 factors listed in R14-2-704(B). In addition to this review, and as required by Decision No. 76632, the Ascend team performed an independent review of the IRPs filed by APS, TEP, and UNSE. Rather than repeating the results of the Ascend team's analysis, Staff has included public versions of the Ascend team's review as attachments to this Staff Report and incorporates by reference all of the findings presented in the Ascend team's review. Specific elements of the Ascend team's analysis will be discussed throughout this section of the Staff Report.

A. Compliance with Commission Decisions

1. Decision No. 73884 and 75068

Staff concludes AEPCO has satisfied the requirements of Decision No. 73884. AEPCO has continued to participate in the IRP process by filing whatever information, data, criteria, and studies it has used in its 15-year planning scenarios, without the necessity of having its IRP acknowledged by the Commission. Staff recommends the Commission find the information filed by AEPCO satisfies the requirements established in Decision Nos. 73884 and 75068.

As required by Decision No. 75068, APS, TEP, and UNSE have held public pre-filing workshops prior to detailed portfolio planning and per the modified timeline established in Decision No. 76632. Decision No. 75068 also requires that Action Plans must be updated whenever a substantive change in the near-term resource plan occurs. In this IRP process, there were no updates filed to the 2020 Action Plans.

2. Decision No. 76632

In Section 2 of the Ascend team's report (starting at page 11), a summary of compliance with Decision No. 76632, is presented. In addition to this summary, Staff presents the following discussion of compliance with Decision No. 76332:

IRP Timeline

The LSEs complied with all timelines specified in Commission Decision Nos. 76632, 77176, 77574, and 77696.

IRP Rulemaking

Decision No. 76632 ordered that:

> "Staff shall, within 60 days of the effective date of this Decision, open a formal rulemaking docket and, within 120 days of the effective date of this Decision, hold a first in a series of stakeholder workshops to completely revise and reform the existing Resource Planning and Procurement rules, A.A.C. Title 14, Chapter 2, Article 7, to include, but not be limited to Staff recommendations in Finding of Fact 267 and all other necessary and prudent reformations."

Pursuant to Decision No. 76632, on May 29, 2018, Staff opened Docket No. RE-00000A-18-0137 to consider proposed rulemaking to modify the Commission's resource planning and procurement rules.[30] On August 14, 2018, the Commission, at a Commission Staff Meeting, directed Staff to initiate a rulemaking docket to evaluate proposed Arizona energy modernization.[31] In response, on August 17, 2018, Docket No. RU-00000A-18-0284 was opened. The resource planning and procurement rules were one of 14 different sets of rules to be included in the scope of Docket No. RU-00000A-18-0284.

Proposed modifications to the IRP Rules have been presented in the Commission's PER (see Exhibit A-1 of Decision No. 78041 (the "Energy Rules")).

The modifications to the IRP Rules are summarized as follows: the new proposed process focuses on the early stages of resource portfolio development, through approval of the load forecast and needs assessment, approving ASRFI and ASRFP language, and the use of a Resource Planning Advisory Council, all of which better allow the Commission to ensure that an LSE considers the factors necessary for the cost-effective provision of safe and reliable electric service to its customers while meeting carbon emissions reduction standards. The new proposed process would require the Commission to review and approve a utility's load forecast and needs assessment before the utility creates its IRP, the Commission or Staff approve a utility's ASRFI language before the procurement process begins, and the utilities use an ASRFP process, all of which are consistent with industry best practices for all-source electric generation procurement.

On June 16, 2021, the Commission issued Decision No. 78041, ordering Staff and the Commission's Legal Division to file a Notice of Supplemental Rulemaking ("NSPRM") with the Office of the Secretary of State, including replacing the Commission's resource planning and procurement rules with new resource planning and procurement rules.[32] On August 16 and 19, 2021, the Commission's Hearing Division held oral proceedings on the NSPRM, pursuant to Decision No. 78041. On September 20, 2021, Staff filed a summary of all written and oral comments received concerning the NSPRM between June 16, 2021, and August 20, 2021, Staff's response to these comments,[33] and Staff's second revised Economic Impact Statement[34] for the rulemaking, pursuant to Decision No. 78041.

Decision No. 78041, requires that the Commission's Hearing Division shall issue a Recommended Opinion and Order, for consideration at a Commission Open Meeting, on whether and in what manner the rulemaking should move forward. On December 1, 2021, the Commission's Hearing Division issued this Recommended Opinion and Order, and the issue is currently scheduled for Commission consideration at the December 15 and 16, 2021 Open Meeting to determine whether and in what manner the rulemaking should move forward.

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[30] https://docket.images.azcc.gov/0000189858.pdf

[31] https://docket.images.azcc.gov/0000191382.pdf?i=1637185450032

[32] https://docket.images.azcc.gov/0000203919.pdf

[33] https://docket.images.azcc.gov/E000015763.pdf

[34] https://docket.images.azcc.gov/E000015762.pdf

Third Party Analyst

As previously discussed, Staff executed a contract with the Ascend team to perform an independent review of the 2020 IRPs. In its list of alternative portfolios, as specified in Decision No. 76632, Ascend included portfolios based on the Commission's PER.

The Ascend team's report was filed on August 11, 2021, in the docket. Subsequent to the filing, the Ascend team identified the need to make corrections to its report. As a result, a corrected copy of the independent review of the IRPs was filed on August 13, 2021, in the docket.[35] An addendum, containing the Energy Rules analysis specific to UNSE, was filed in the docket on September 21, 2021.

The Ascend team's recommendations will be discussed in detail in Section III(V)(I) of this report.

Forecasted Change in Costs

According to Staff's and the Ascend team's review of the 2020 IRPs, each LSE included the forecasted change in costs of both established and emerging technologies in the portfolio analyses.

As noted by the Ascend team's report, APS provided Staff and Ascend with future cost curves for all potential resources as part of a data request. The Ascend team concludes that APS technology cost assumptions for renewables and batteries used in the IRP are in line with other reputable resources, such as the National Renewable Energy Laboratory ("NREL").

For TEP and UNSE, capital cost assumptions for solar, wind, and storage display future cost declines. The Ascend team also notes that these cost declines are consistent with commonly used industry benchmarks, such as NREL's Annual Technology Baseline and Lazard.

Tabular Representation of Portfolios

Decision No. 76632, requires a detailed representation that provides a breakdown by capacity and energy mix contributions for each analyzed portfolio, including a breakdown of each specific technology type, the capacity contribution to the portfolio of each specific technology type, the per MW of that specific technology, and total cost.

APS provided such a table, but did not break down by specific technology, cost per MW of each, or total cost.

[35] https://docket.images.azcc.gov/E000015107.pdf?i=1636386156053

Staff concludes TEP and UNSE did not include a tabular representation that provides a breakdown by capacity and energy mix contributions for each portfolio that was analyzed, similar to Table ES-2 on Page 13 of APS's 2017 IRP.

Each company should explore methods to better present the detailed resources contained in each portfolio such as including loads and resources tables in appendices attached to the IRP.

Public Workshops

Decision No. 76632, requires that the LSEs, except APECO, coordinate with Staff to hold a public workshop within 60 days after filing future preliminary IRPs to discuss portfolios. On September 28, and 29, 2021, in coordination with all LSEs as ordered in Decision No. 76632, Staff held a public workshop to discuss future portfolios.

Natural Gas Storage

Decision No. 76632, requires that the LSEs, except APECO, address natural gas storage in greater detail in their IRPs, including efforts to develop natural gas storage, costs and benefits of natural gas storage, risks of lack of market area natural gas storage in Arizona, and sensitivity analysis of various natural gas price scenarios.

APS, TEP, and UNSE each provide sensitivity analysis of various natural gas price scenarios in the 2020 IRPs. APS also briefly mentioned the risks of pipeline disruptions in a short passage on page 49 of its 2020 IRP.

However, APS and TEP failed to adequately discuss the costs and benefits of natural gas storage. TEP and UNSE also failed to discuss the risks of a lack of market area natural gas storage in Arizona and only briefly describe what would be required to advance efforts to develop natural gas storage without describing the status of any efforts to develop storage or lack thereof. In addition to these observations made by Staff, the Ascend team notes, "overall, the discussion of gas storage is brief and does not provide a detailed analysis of the arguments for or against developing natural gas storage in Arizona. Future IRPs should provide additional in-depth analysis related to system reliability and the risks/consequences of pipeline distribution."

Furthermore, the Ascend team states, the recent "situation on the Texas grid in February 2021 highlighted the need for utilities to investigate the interconnected risks of the gas system failing to deliver adequate supply to power plants during periods of extreme weather. While Arizona is unlikely to experience the same cold weather conditions [as Texas did in February 2021], we recommend APS include in their next IRP an analysis of power system resiliency to extreme weather, including correlated risks to both the power and gas systems. Gas storage could potentially provide a hedge against natural gas supply interruptions and price shocks that would ultimately benefit APS customers." Staff believes this is an appropriate recommendation for TEP and UNSE as well. Therefore, Staff recommends APS, TEP, and UNSE include in future IRPs a comprehensive analysis of power system resiliency to extreme weather, including correlated risks to both the power and gas systems.

Regarding natural gas price scenarios, APS performed a sensitivity analysis with low, base, and high natural gas price forecasts. The TEP and UNSE IRPs also include a range of future gas prices. Natural gas prices are further discussed in Section V(E)(1) of this report.

EE Workshops

Decision No. 76632, required Staff to conduct EE workshop(s) to allow stakeholders to provide input regarding the future of EE beyond the 2020, expiration date contained in the Commission's rules. On September 19, 2019, Staff conducted an EE workshop to allow stakeholders to provide input regarding the future of EE.

Storage Technologies and Alternatives

Decision No. 76632, required APS, TEP, and UNSE to include an analysis of a reasonable range of storage technologies and chemistries and an analysis of anticipated future energy storage cost declines. These requirements are further discussed in Decision No. 76295.

APS described a range of storage technologies in Chapter 2 of its IRP, TEP discussed storage technologies in Chapter 10 of its IRP, and UNSE discussed storage technologies in Chapter 9 of its IRP. Each LSE also included forecasted costs of storage technologies. The NREL's Annual Technology Baseline information was utilized in the IRPs as well as cost information from Wood Mackenzie.

The Ascend team notes the following:

- APS should consider further analysis to determine the most effective schedule for energy storage deployments over a range of scenarios and cost projections. Capacity expansion modeling, resource adequacy analysis, and production cost modeling with sub-hourly dispatch would fully capture the costs and benefits of energy storage technology over time and help APS select the optimal storage deployment pathway.
- The TEP and UNSE IRPs consider future cost declines of storage that are consistent with common forecast sources but does not provide sufficient consideration to alternate storage technologies. This is particularly important given the different cost versus power tradeoffs of different storage technologies, and the corresponding services that they are suited for providing the grid. In addition to lithium ion, storage options that should be considered are flow batteries, liquid air, metal air, hydrogen/renewable fuels, and other emerging technologies.

- Overall, the discussion of storage technologies is very brief. Future IRPs should provide a more detailed discussion of the options and applications of storage at different durations, as well as evolution in effective load carrying capabilities as storage penetration increases.

Additional information regarding technology costs is presented in Section V(D) of this report.

Load Growth Report

APS was required to prepare a report within 90 days of the Commission's Decision justifying its 2015 and 2016 IRP load growth projections including a "no growth" scenario, a "low growth (<1 percent growth)" scenario, and the resultant implications on APS's resource selections under each scenario. In addition, the report also required a discussion regarding how each of the required scenarios affect APS's Three-Year Action Plan.

On June 29, 2018, APS filed the report pursuant to Decision No. 76632.[36] The Ascend team reviewed APS's load forecast development and assumptions in Section 2.1 of its report (see page 17).

Specific Portfolio Requirements

Decision No. 76632, required that in the next IRPs, APS, TEP, and UNSE must include "no growth" and "low growth" (<1 percent) scenarios.

APS presents a no-growth, low growth, and base case scenario for its load forecast. The results of APS's analysis of the growth scenarios are summarized in Table 7-11 on page 154 of its IRP. In Chapter 8 of its 2020 IRP, TEP presents its load growth scenarios which include a base, no growth, low growth, and low and high EV sales. In Chapter 9 of its IRP, UNSE presents a base, low growth, no growth, and high growth scenarios.

Although APS, TEP, and UNSE have complied with this requirement, the IRPs should discuss in greater detail the effect of different load forecast scenarios on portfolio selection and the LSE's Action Plan. In addition, the Ascend team notes future IRPs should:

- Evaluate an "electrify everything" pathway, which would imagine a near total transition to electrified transportation and building sector. Load growth could also be higher than expected due to climate driven increases in average temperature and more frequent extreme heat waves; and

- Provide greater discussion of the risks of market dependence, over-procurement, and the portfolio cost sensitivity to inaccurate load forecasts.

[36] https://docket.images.azcc.gov/0000189593.pdf?i=1636503452864

Decision No. 76632, also requires that APS, TEP, and UNSE also analyze, along with their preferred portfolio, at least one portfolio where the addition of fossil fuel resources is no more than 20 percent of all the resource additions. In addition, each was required to work in good faith with each of the stakeholders and any Tribal Nations located in Arizona that desire to participate in developing the portfolio.

According to Table 7-2 of the APS IRP, all three of APS's portfolios comply with this requirement. Portfolio P04 of TEP's IRP, and Portfolio 3 of UNSE's IRP also comply with this requirement.

In addition, APS, TEP, and UNSE were required to analyze, along with their preferred portfolio, at least one portfolio that includes, as a 15 year forecast, all of the following: the lesser of 1,000 MW of energy storage capacity or an amount of energy storage capacity equivalent to 20 percent of system demand, at least 50 percent of "clean energy resources," which are resources that operate with zero net emissions beyond that of steam, of which 25 MW of nameplate capacity running at no less than 60 percent capacity factor are renewable biomass resources; and at least 20 percent of DSM.

APS's Accelerate Portfolio complies with this requirement according to Table 7-2 of its IRP; TEP's Portfolio P05 complies with this requirement according to Table 19 of its IRP; and UNSE's Portfolio 1 complies with this requirement according to the table on page 99 of its IRP.

Resource portfolio development will be discussed in further detail in Section III(V)(H) of this report.

<u>TEP Action Plan Update</u>

TEP was required to file an update to its Three-Year Action Plan to reflect its announced intention to acquire Unit 2 of the gas-fired GRPS within 30 days of the Decision No. 76632. TEP filed an update to its Action Plan on May 1, 2018.

B. Annual Renewable Energy, Distributed Energy, and Energy Efficiency Requirements

Pursuant to R14-2-703(F)(4), (5), and (6) each IRP (except AEPCO's) must meet the requirements of the Annual Renewable Energy Requirement ("ARER"), the Distributed Renewable Energy Requirement ("DRER"), and the EE Standard.

The ARER requires utilities to procure 10 percent of annual retail sales from renewable energy in 2020, and this requirement increases by one percent each year until it reaches 15 percent in 2025. Affected utilities are also required to produce 30 percent of the renewable energy requirement from distributed renewable resources in 2020, and throughout the IRP planning period. The EE Standard requires each affected utility to reduce its retail sales by 22 percent in 2020.

Renewable Energy

APS's Bridge Portfolio projects 16.5 percent of sales will be met using renewable energy for 2020, 32.0 percent for 2025, and 58.3 percent for 2035. TEP indicated that it set its goal to provide 30 percent of its power from renewable resources by 2035, while also satisfying the 10.0 percent requirement in 2020. UNSE planned to meet the requirement by producing 92 GWh of renewable energy in 2020.

Distributed Energy

APS plans to meet and exceed that goal by 76 percent in 2020, 58 percent in 2025, and 76 percent in 2035. TEP and UNSE anticipate having 20 percent of renewable energy as retail sales, and project that amount to increase to 50 percent in 2025. According to TEP's and UNSE's 2021 REST Plans (filed on July 1, 2020), TEP and UNSE are in compliance with the Renewable Energy and Distributed Energy requirements as set forth in the A.A.C. R14-2-1804.

Energy Efficiency ("EE")

According to APS's IRP, it has met the 2020 EE Standard set in Decision No. 75679, with 23.66 percent. According to the IRPs filed by TEP and UNSE, each LSE has implemented programs to achieve the 2020 EE Standard.

Staff concludes each 2020 IRP (except AEPCO's) meets the requirements of the ARER, the DRER, and the EE Standard.

C. Load Forecast and Needs

Pursuant to R14-2-704(B)(4), Staff reviewed the 2020 IRPs for information related to the uncertainty in demand and supply analyses, forecasts, and plans, and whether plans were sufficiently flexible to enable the LSE to respond to unforeseen changes in supply and demand factors. Each LSE presents load forecasts, scenarios, and resource needs in its IRP that addresses this. In addition, the Ascend team's report discusses the load forecasts for each LSE in detail.

APS forecasts that over the planning period, 2020-2035, annual peak demand will grow at 2.1 percent and the energy needs will be increased by a 2.7 percent. This growth was projected by the company, using factors like the population, data center or economic growth and the change in customers trends related to distributed generation and the use of EV's. APS states its capacity needs will be increased approximately 175 MW annually, which corresponds to a total of 2,600 MW in the planning period, and the energy needs will grow by 15,300 GWh. APS states that with expected peak load to grow by 550 MW, APS will need new resources additions over the planning period.

Staff notes that several stakeholders expressed concern with unrealistically high load forecasts. The Ascend team's analysis concludes, "given assumed growth in customers, we feel these are reasonable growth rates for energy. We also find that lower relative demand growth is a reasonable expectation as peak demand becomes muted by adoption of load modifying technologies like behind-the-meter solar and storage, controllable loads, and smart EV charging." In addition, the Ascend team's report goes on to state, "in Verdant's opinion, APS's IRP demand forecast was developed using industry best practices. They hired third-party consultants to assist in the development of forecasts of DSM opportunities or DSM potential and EV Sales and Energy Consumption. They hired Itron, a leading load forecasting firm, to review the APS load forecast, and APS responded to this review by adopting one of Itron's suggested methods to improve the residential load forecast. APS's growth in their load forecast is largely due to forecasts of growth in Arizona's population, business growth and growth in data centers. Given previous growth in Arizona's population, the forecasts of these underlying input to energy consumption appear within the likely bounds."

TEP based its firm resource capacity, for the planning period of 2020-2035, on its initial assumptions related to coal and natural gas resources and the goal of providing load with 30 percent renewable energy by 2030.

According to the previous assumptions and after adding a 15 percent reserve margin to the expected load, TEP will have enough resources available to satisfy that load during the first years of the studying period, at the time of peak demand. However, starting in 2030, the company will need additional resources to fulfill the load necessities.

UNSE's forecast for the study period, is based on the same assumptions that TEP used. Using also a 15 percent reserve margin on top of the expected load, the company will need around 193 MW in additional resources by 2025, to satisfy the load estimation for that year. The extra power required will be increased in the following years, showing the need for additional resources.

According to the Ascend team, TEP and UNSE's forecasting approaches:

> "conform to a variety of standard industry practices, each appropriate for its respective sector. The residential and commercial sector forecasts are based on a combination of a use-per-customer forecast and a customer forecast, each relying on ARIMA models with exogenous variables. The two forecasts are multiplied to generate the total sales. While not the most common approach, this hybrid method helps the utilities better isolate the account for how EE and distributed generation influence net retail sales versus gross consumption. The customer forecasts assess a variety of models using intuitive drivers (e.g., population, commercial establishment growth) and accounts for weather and calendar effects. Final model selection considers the out-of-sample performance of the candidate models. For these load forecasts, the IRP relied on a variety of reliable sources for their data, including IHS Global Insight, The University of Arizona Forecasting Project, Arizona Department of Commerce, the U.S. Census Bureau, and the National Oceanic and Atmospheric Administration

(["NOAA"]). Peak demand is forecasted using a model that combines weather and sales data to estimate the peak demand. While this approach has worked well historically, a potential future shortcoming in this approach is an inability to anticipate how demand side resources might shift both the magnitude and timing of peak demand. The peak demand forecast provides little information on the typical timing of system peaks, and thus there is not sufficient data to determine how relevant this might be for these two utilities."

Staff concludes that the load forecasts and IRPs were developed before the onset of the COVID-19 pandemic. As a result, the economic impacts of the pandemic, and the associated impact on future electric demand, could not have been adequately considered. It is unclear what changes to the Action Plans, if any, would be required based on these factors. TEP states that some of its alternative load scenarios could reasonably be expected to include the effects of the pandemic on electricity demand, and that its preferred scenario is no more sensitive to load uncertainties than other portfolios considered under a stochastic risk analysis. APS stated in its IRP that it is prepared to update its Action Plan as needed, due to the Covid-19 pandemic.

Staff recommends that APS, TEP, and UNSE file, as a compliance item in this docket, updated Five-Year Action Plans that describe whether near-term resource selections have been impacted due to changes in the LSE's load forecast attributable to the COVID-19 pandemic within 90 days of the Commission's decision in this matter.

D. Resources Considered

Pursuant to R14-2-703(E) and R14-2-704(B)(3) & (4), Staff has summarized the resources considered, and the technology cost assumptions presented, in each IRP:

Resources	APS	Capital Cost ($/kW)	Fixed O&M ($/kW-Yr)
NUCLEAR			
Advanced Nuclear	X	$6,830.00	$121.13
Small Modular Reactor (SMR)	X	$5,605.00	$173.35
NATURAL GAS			
Large Frame Combustion Turbine	X	$652.00	$11.58
Aeroderivative Combust on Turbine	X	$1,512.00	$8.86
Combined Cycle	X	$994.00	$7.72
MICROGRID			
Genset	X	$946.00	$5.88
ENERGY STORAGE			
Battery Energy Storage System (Li-ion)	X	$1,225.00	$24.50

Compressed Air Energy Storage (CAES)	X	$3,878.00	$22.74
Pumped Storage Hydro	X	$3,546.00	$49.64
Flow Battery	X	$1,570.00	$31.40
GRID-SCALE SOLAR			
Thin Film Solar PV - Single Axis Utility	X	$1,160.00	$17.86
Thin Film Solar PV - Fixed Util ty	X	$1,084.00	$17.86
Solar PV + Battery Energy Storage System (PVS)	X	$2,385.00	$42.36
Solar Thermal Tower with Storage	X	$7,107.00	$83.46
Distributed Solar			
Thin Film Solar PV - Fixed Commercial	X	$1,260.00	$21.00
Thin Film Solar PV - Fixed Residential	X	$2,687.00	$30.77
OTHER RENEWABLE ENERGY SOURCES			
Southwest Wind	X	$1,343.00	$34.73
Geothermal	X	$3,034.00	$122.00
Biomass	X	$4,666.00	$134.82

Resources	TEP	Capital Cost ($/kW) 2024	Fixed O&M ($/kW-Yr) 2024
Energy Efficiency	X	N/A	N/A
Demand Response	X	Customer Load Control Programs	
Solar PV (Single-Axis Tracking)	X	$817.00	$21.56
Solar PV (Fixed Tilt)	X	$668.00	$19.41
Solar PV (Comm & Industrial)	X	N/A	N/A
Solar PV (Residential)	X	N/A	N/A
Solar Thermal (8-Hour Storage)	X	$4,991.00	$82.19
NM Wind	X	$1,335.00	$32.81
AZ Wind	X	$1,317.00	$32.36
Combustion Turbine (Aeroderivative)	X	$925.00	$13.08
Combustion Turbine (Frame)	X	$771.00	$13.08
Compressed Air Storage	X	N/A	N/A
Natural Gas Combined Cycle (Baseload)	X	$1,085.00	$37.96
Natural Gas Combined Cycle (Intermediate Load)	X	$1,085.00	$37.96
Reciprocating Engines	X	$874.00	$12.34
Four-Hour Battery Storage	X	$1,081.00	$32.31
Eight-Hour Battery Storage	X	$1,945.00	$55.39
Biomass	X	N/A	N/A
Pumped Hydro Storage	X	N/A	N/A

Resources	UNSE	Capital Cost ($/kW) 2024	Fixed O&M ($/kW-Yr) 2024
Energy Efficiency	X	N/A	N/A
Demand Response	X	Customer Load Control Programs	
Solar PV (Single-Axis Tracking)	X	$817.00	$21.56
Solar PV (Fixed Tilt)	X	$668.00	$19.41
Solar PV (Comm & Industrial)	X	N/A	N/A
Solar PV (Residential)	X	N/A	N/A
Solar Thermal (8-Hour Storage)	X	$4,991.00	$82.19
NM Wind	X	$1,335.00	$32.81
AZ Wind	X	$1,317.00	$32.36
Combustion Turbine (Aeroderivative)	X	$925.00	$13.08
Combustion Turbine (Frame)	X	$771.00	$13.08
Compressed Air Storage	X	N/A	N/A
Natural Gas Combined Cycle (Baseload)	X	$1,085.00	$37.96
Natural Gas Combined Cycle (Intermediate Load)	X	$1,085.00	$37.96
Reciprocating Engines	X	$874.00	$12.34
Four-Hour Battery Storage	X	$1,081.00	$32.31
Eight-Hour Battery Storage	X	$1,945.00	$55.39
Biomass	X	N/A	N/A
Pumped Hydro Storage	X	N/A	N/A

As noted by the Ascend team's report, APS provided Staff and Ascend with future cost curves for all potential resources as part of a data request. The Ascend team concludes that APS technology cost assumptions for renewables and batteries used in the IRP are in line with other reputable resources, such as the NREL. For TEP and UNSE, capital cost assumptions for solar, wind, and storage display future cost declines. The Ascend team also notes that these cost declines are consistent with commonly used industry benchmarks, such as NREL's Annual Technology Baseline and Lazard.

Staff concludes APS, TEP, and UNSE have included a reasonable range of technologies and associated costs in the 2020 IRPs.

E. Assumptions

Pursuant to R14-2-703(E) and R14-2-704(B)(3) & (4), Staff has summarized the natural gas prices forecasts and CO2 cost forecasts that are presented in the 2020 IRPs.

1. Natural Gas Price Forecasts

The three portfolios presented by APS have different approaches in the use of natural gas as a resource. The Bridge portfolio states that natural gas is important as a bridge resource between the use of coal and renewable energy technologies, allowing APS to provide reliable service. The Shift and Accelerate portfolios, move APS away from natural gas, not allowing for any new natural gas generation to be procured.

The Ascend team notes in its report (see Section 3.3.2) that from 2021 to 2035, APS estimates natural gas prices to rise from \$2.25 per Metric Million British Thermal Unit ("MMBTU") to \$2.80 per MMBTU. Ascend states it used a similar method as APS to derive natural gas prices and produced a forecast slightly lower than the APS forecast.

The addition of natural gas combined plants is not considered in any of the portfolios presented by TEP. In addition, UNSE is not planning to add natural gas resources in the future, for any of the portfolios presented for the study period. TEP and UNSE forecast prices to reach approximately \$3/MMBTU in 2030, and a maximum of \$4/MMBTU by 2038.

Staff concludes that the price of natural gas has both short- and long-term impacts on an LSE's resource procurement decisions. Given the expressed desire by APS, TEP, and UNSE, in the 2020 IRPs, to achieve significant carbon emissions reductions, the impact of a wide range of natural gas prices on resource procurement decisions needs to be thoroughly discussed in the IRP. Similarly, the Ascend team notes,

"policy and economic trends portend a decline in the demand for natural gas. As renewables generate more of the system energy, gas units' capacity factors will decline. At the same time, air source heat pumps are expected to reduce residential and commercial end use of natural gas. The implications of winding down the gas system as well as replacing natural gas with hydrogen and/or renewable natural gas should be studied by APS in the next IRP as part of the broader push for decarbonization."

TEP and UNSE should also study these implications in future IRPs.

Staff recommends that APS, TEP, and UNSE include in future IRPs a dedicated section that explicitly discusses the LSE's natural gas price assumptions, the resulting impact of those assumptions on the LSE's short- and long-term resource procurement decisions, and the implications of declining natural gas usage as the LSE shifts its resource mix to achieve emissions reductions.

2. CO2 Emission Cost Forecasts

All the portfolios presented by APS for the planning period, 2020 to 2035, show substantial reductions of carbon emissions compared to 2005 levels. APS assumes that the emissions of CO2 will be charged starting at $19 per ton in 2025 and escalate over time.

TEP and UNSE utilize the data contained in Wood Mackenzie's North America Power and Renewables Long-Term Outlook (LTO), to forecast the CO2 emissions prices. This LTO includes a "Federal Carbon Case", which implements a $2.40/ton on CO2 emissions from electric generating units, beginning in 2028, and incrementing about $2.50/ton per year after that.

Forecasting the future cost of CO2 will continue to play an important role in understanding the costs and benefits of the various portfolios presented by each LSE in its IRP. Staff recommends APS, TEP, and UNSE closely monitor federal legislation, and any other relevant legislation, related to a carbon tax and include in future IRPs a relevant discussion of the impacts of such legislation on the development of the IRP.

F. Transmission Considerations

Pursuant to R14-2-704(B)(6) Staff reviewed the IRPs for information related to the reliability of the transmission grid. In addition, R14-2-703(D)(1)(g) requires the IRP include, "an explanation of the need for and purpose of all expected new or refurbished transmission and distribution facilities, which explanation shall incorporate the load-serving entity's most recent transmission plan filed under A.R.S. 40-360.02(A) and any relevant provisions of the Commission's most recent Biennial Transmission Assessment ("BTA") decision regarding the adequacy of transmission facilities in Arizona."[37]

The 11th BTA is the most recently completed BTA. The 11th BTA was approved by the Commission on May 5, 2021 in Decision No. 77999.[38]

1. APS

In its 2020-2029 Ten-Year Transmission Plan, APS lists several new transmission projects which include: approximately 26 miles of 230 kiloVolt

[37] *See* A.A.C. R14-2-703(D)(1)(g).

[38] *See* Docket No. E-00000D-19-0007

("kV") transmission lines, 3 miles of 115kV transmission line upgrades, and 38 new transformers.

APS is also examining the ability of the transmission system to deliver out of state wind resources to the APS system, since the Arizona wind facilities are not usually in the vicinity of APS transmission lines. APS states that out of state high capacity factor wind resources are becoming difficult to secure, due to the large number of utilities seeking access to them, and gaining access to these wind farms, can present a significant additional cost to APS due to the necessary transmission buildout or upgrades.

APS states it is in the process of transitioning the methodology used to calculate its Available Transfer Capability ("ATC"). This task will take approximately two years to complete and could result in a more efficient use of APS's transmission system, resulting in avoiding future construction and additional flexibility in siting generation resources.

2. TEP

TEP has obtained the rights to develop the Vail-Tortolita portion of the Southline Transmission Project. This project will rebuild a 62-mile portion of the existing Western Area Power Administration's ("WAPA") 115 kV transmission line between Apache and Saguaro Generation Stations. This line, routed to the south and west of Tucson, will be rebuilt as a double circuit transmission line to 230 kV standards with the TEP circuit operating at 230 kV, and the WAPA circuit continuing the operation at 115 kV. The TEP circuit, will have tie points at three TEP substations (Vail, DeMoss Petrie and Tortolita) at different voltage levels.

In December 2016, E3, performed a study for TEP, which estimated that joining CAISO Western EIM, could benefit TEP. Since then, two utilities (PNM and SRP) with significant transmission connections with TEP, have joined the Western EIM. TEP states that this will improve the company's access to market opportunities while reducing real time non-EIM bilateral trading opportunities as others enter the market. TEP signed an agreement with CAISO in May 2019, to join the Western EIM in April 2022.

TEP states the transmission system was designed to accommodate the coal generation fleet that is geographically distant from the load centers. The integration of renewable energy projects together with the reduction of coal resources will most likely have an impact on the operation of the transmission grid. To respond to this issue, TEP has placed into service RICE generators and 21 MW of Battery Energy Storage System at selected renewable resource locations.

3. UNSE

In August 2020, E3 evaluated the potential economic benefits of UNSE's participation in the Western EIM. As UNSE operated within TEP's Balance Authority, the current study will update the 2018 study completed for TEP with UNSE's generators, transmission, and loads, to assess the benefits to the combined TEP-UNSE system. UNSE benefits will be estimated subtracting those only relative to TEP.

4. Regional Transmission Issues

On July 23, 2021, the Commission opened Docket No. E-00000A-21-0271 to investigate regional planning, markets, and collaborations among LSEs in the Western Interconnection. The docket also investigates the question of mandatory or voluntary participation in RTO.

Discussions regarding the benefits of regional collaboration across the Western United States have gained traction recently. Given the commitments made by many Western states to transition to cleaner energy mixes, various stakeholders have raised questions regarding what opportunities exist for improved collaboration to achieve cost savings and greater efficiencies.

On October 6, 2021, APS announced that several electric providers in the Western United States have committed to jointly evaluate regional market solutions.[39] Specifically, the informal Western Markets Exploratory Group ("WMEG"), "are exploring the potential for a staged approach to new market services, including day-ahead energy sales, transmission system expansion, and other power supply and grid solutions consistent with existing state regulations. The group hopes to identify market solutions that can help achieve carbon reduction goals while supporting reliable, affordable service for customers." The group includes Xcel Energy – Colorado, APS, Black Hills Energy, Idaho Power, NV Energy, Inc., PacifiCorp, Platte River Power Authority, Portland General Electric, Puget Sound Energy, Salt River Project, Seattle City Light, and TE P.

The Ascend team noted that future modeling enhancements should consider LSEs transitioning away from a "dispatch-to-load" concept towards one that incorporates further integration into Western energy markets. More specifically, the Ascend team recommended incorporating hourly and sub-hourly prices from the Western EIM and a future Extended Day Ahead Mechanism. Similarly, stakeholders throughout this IRP cycle have filed comments recommending TEP include the benefits of EIM participation in future IRPs.

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39 https://www.aps.com/en/About/Our-Company/Newsroom/Articles/Several-Western-power-providers-announce-plans-to-explore-market-options

Participation in regional markets, such as the EIM, may provide benefits to ratepayers and result in more efficient resource procurement. Therefore, APS, TEP, and UNSE should improve future IRPs by analyzing to what extent regional market participation affects near- and long-term resource procurement actions. Staff recommends that APS, TEP, and UNSE include in future IRPs a discussion of participation in regional markets and the effects of that participation on near- and long-term resource procurement actions.

G. Environmental Considerations

Pursuant to R14-2-704(B)(7) Staff reviewed the IRPs for information related to the environmental impacts of resource choices and alternatives. The summary of environmental impacts of the Preferred Portfolios, identified in the 2020 IRPs, can be found in Section III of this Staff Report.

1. Existing Air Emission Environmental Impacts

A.A.C. R14-2-703(B)(1)(p) requires the load-serving entity to provide for each generating unit and purchased power contract for the previous calendar year a description of the environmental impacts, including air emissions quantities (tons/lbs) and rates (/MWh) for CO2, NOX, SO2, Hg, particulates (PM10 and PM2.5), and other air emissions subject to current or expected regulation.

a) APS

APS provided the required data to satisfy A.A.C. R14-2-703(B)(1)(p) for historical year 2020, on April 1, 2021, and for historical year 2019 on April 1, 2020, in Docket No. E-00000V-19-0034.

b) AEPCO

AEPCO provided the required data to satisfy A.A.C. R14-2-703(B)(1)(p) for historical year 2020, on April 1, 2021, and for historical year 2019 on April 1, 2020, in Docket No. E-00000V-19-0034.

c) TEP

TEP provided the required data to satisfy A.A.C. R14-2-703(B)(1)(p) for historical year 2020, on April 1, 2021, and for historical year 2019 on April 17, 2020, in Docket No. E-00000V-19-0034.

TEP also provided as an appendix to its 2020 IRP a study conducted with the UAIE to assist in determining the Company's relationship between the Company's direct CO_2 emissions and the goal of limiting global temperature rise to 1.5 C.

d) UNSE

UNSE provided the required data to satisfy A.A.C. R14-2-703(B)(1)(p) for historical year 2020, on April 1, 2021, and for historical year 2019 on April 17, 2020, in Docket No. E-00000V-19-0034.

2. *Existing Water Consumption Environmental Impacts*

A.A.C. R14-2-703(B)(1)(q) requires for each generating unit and purchased power contract for the previous calendar year a description of the water consumption quantities and rates.

e) APS

APS provided the required data to satisfy A.A.C. R14-2-703(B)(1)(q) for historical year 2020, on April 1, 2021, and for historical year 2019, on April 1, 2020, in Docket No. E-00000V-19-0034.

f) AEPCO

AEPCO provided the required data to satisfy A.A.C. R14-2-703(B)(1)(q) for historical year 2020, on April 1, 2021, and for historical year 2019, on April 1, 2020, in Docket No. E-00000V-19-0034.

g) TEP

TEP provided the required data to satisfy A.A.C. R14-2-703(B)(1)(q) for historical year 2020, on April 1, 2021, and for historical year 2019, on April 17, 2020, in Docket No. E-00000V-19-0034.

h) UNSE

UNSE provided the required data to satisfy A.A.C. R14-2-703(B)(1)(q) for historical year 2020, on April 1, 2021, and for historical year 2019, on April 17, 2020, in Docket No. E-00000V-19-0034.

3. Existing Coal Ash Environmental Impacts

A.A.C. R14-2-703(B)(1)(r) requires for the previous calendar year a description of the tons of coal ash produced per generating unit.

i) APS

APS filed historical data for year 2019 on April 1, 2020, and for year 2020, on April 1, 2021, in Docket No. E-00000V-19-0034 containing the required data to satisfy A.A.C. R14-2-703(B)(1)(r) regarding its coal generating units.

j) AEPCO

AEPCO provided the required data to satisfy A.A.C. R14-2-703(B)(1)(q) for historical year 2020, on April 1, 2021, and for historical year 2019, on April 1, 2020, in Docket No. E-00000V-19-0034.

k) TEP

TEP filed historical data for year 2019, on April 17, 2020, and for year 2020, on April 1, 2021, in Docket No. E-00000V-19-0034 containing the required data to satisfy A.A.C. R14-2-703(B)(1)(r) regarding its coal generating units.

l) UNSE

UNSE filed historical data for year 2019, on April 17, 2020, and for year 2020, on April 1, 2021, in Docket No. E-00000V-19-0034, but this data contains no information about the tons of coal ash produced per generating unit. While UNSE does not operate any coal generating units and it is reasonable that UNSE would not generate any coal ash as a result, UNSE could have included a table on page 43 of its 2019, data and page 30 of its 2020, data indicating zero coal ash tons produced per unit in order to strictly comply with A.A.C. R14-2-703(B)(1)(r).

2. Projected Environmental Impacts

A.A.C. R14-2-703(D)(1)(a) requires projected data for each of the items listed in A.A.C. R14-2-703(B)(1), for each generating unit that is expected to be new or refurbished during the period, which shall be designated as new or refurbished, as applicable, for the year of purchase or the period of refurbishment. This includes air emissions, water consumption, and coal ash. Applicable sections in A.A.C. R14-2-703(B)(1) include subsections (B)(1)(p) - (r).

a) APS

Projected data for each generating unit and purchased power resource are provided in the Attachments D.1(a)(8)-1 to –3, one for each of its IRP portfolios. APS provides only aggregate total projections for 2020-2035 for CO2 emissions, CO emissions, volatile organic compounds ("VOCs"), NOx emissions, SO2 emissions, Hg emissions, PM10 emissions, coal fly ash collected, coal fly ash bottom collected, and water consumption. APS does not break down this data by generating unit as required by A.A.C. R14-2-703(D)(1)(a).

b) AEPCO

AEPCO provided its response to the requirements of A.A.C. R14-2-703(D)(1)(a) on August 26, 2020, in Docket No. E-00000V-19-0034.

c) TEP

TEP provides projected CO2 emissions and water consumption from 2020-2035, for its preferred portfolio in the Executive Summary and discussion of its Preferred Portfolio of its 2020 IRP. However, it does not provide a breakdown per generating unit, nor does it provide a breakdown for the various criteria air pollutants or for coal ash. Therefore, its 2020 IRP does not comply with the requirements of A.A.C. R14-2-703(D)(1)(a).

In Chapter 6, TEP discusses current and expected environmental regulations and the effect they may pose on the utility. These regulations include Regional Haze, the U.S. Affordable Clean Energy Rule, and Ozone National Ambient Air Quality Standards.

d) UNSE

Staff was unable to identify any location in its 2020 IRP where UNSE provides projected environmental impacts for its preferred portfolio as required by A.A.C. R14-2-703(D)(1)(a).

3. Costs of Compliance - Existing and Expected Environmental Regulations

A.A.C. R14-2-703(D)(1)(h) requires the load serving entity to provide a 15-year resource plan, providing for each year cost analyses and cost projections, including the cost of compliance with existing and expected environmental regulations.

a) APS

In response to A.A.C. R14-2-703(D)(1)(h), APS provides cost analyses and projections in the IRP attachments D.10-1 to –3 for each of its portfolios. The cost of existing and expected environmental regulations is embedded within the capital and operations and maintenance figures.

b) AEPCO

AEPCO provided its response to the requirements of A.A.C. R14-2-703(D)(1)(h) on August 26, 2020, in Docket No. E-00000V-19-0034.

c) TEP

Staff was unable to identify any location in its 2020 IRP where TEP discusses the costs of compliance with existing and expected environmental regulations, or where TEP provides a year-by-year breakdown of these costs for its resource plan. This absence of required information does not comply with A.A.C. R14-2-703(D)(1)(h).

d) UNSE

Staff was unable to identify any location in its 2020 IRP where UNSE discusses the costs of compliance with existing and expected environmental regulations, or where UNSE provides a year-by-year breakdown of these costs for its resource plan. This absence of required information does not comply with A.A.C. R14-2-703(D)(1)(h).

4. Environmental Impacts Mitigation and Management

A.A.C. R14-2-703(D)(14) requires the load serving entity to provide descriptions of the demand management programs or measures included in the 15-

year resource plan, including for each demand management program or measure the expected reductions in environmental impacts, including air emissions, solid waste, and water consumption, attributable to the program or measure.

A.A.C. R14-2-703(D)(17) requires a plan for reducing environmental impacts related to air emissions, solid waste, and other environmental factors, and for reducing water consumption.

a) APS

The APS response to A.A.C. R14-2-703(D)(14) is located in section "Response to Rules Section D – Supply" from pp. 183-192. This section provides estimates of 2020-2035 EE environmental impacts reductions by EE program. Attachment D.14(a) and D.14(b) provide detailed information for the EE programs.

The APS response to A.A.C. R14-2-703(D)(17) is located in section "Response to Rules Section D – Supply," particularly Figures D-1 and D-2. These figures provide a plan and timeline for reducing impacts related to air emissions, solid waste, and other environmental factors, and for reducing water consumption.

b) AEPCO

AEPCO provided its response to the requirements of A.A.C. R14-2-703(D)(14) and R14-2-703(D)(17) on August 26, 2020, in Docket No. E-00000V-19-0034.

c) TEP

TEP provides a description of its current DSM programs in its chapter on Planning for an Integrated Grid, including a list of its DSM programs in Table 6. However, TEP does not provide detailed descriptions of each program, nor does it provide the expected reductions in environmental impacts, including air emissions, solid waste, and water consumption, attributable to the program or measure. TEP simply states that its Preferred Portfolio will continue to incorporate high levels of EE, without specifying its plan or the program-level savings from doing so.

TEP describes the environmental attributes of its Preferred Portfolio as prioritizing local area NOx emissions reductions and reduced water consumption, specifying an estimated 80 percent reduction in Tucson area NOx emissions and 70 percent reduction in groundwater consumption. TEP also worked with UAIE to conduct a study to determine its cumulative reductions in carbon emissions from each of the portfolios studied in the IRP. TEP does not provide a plan or description of impacts related to other criteria air pollutants or solid waste impacts as required by A.A.C. R14-2-703(D)(17).

d) UNSE

UNSE provides a description of its current DSM programs in its chapter on Planning for an Integrated Grid, including a list of its DSM programs in Table 8. However, UNSE does not provide detailed descriptions of each program, nor does it provide the expected reductions in environmental impacts, including air emissions, solid waste, and water consumption, attributable to the program or measure. UNSE simply states that its Preferred Portfolio will continue to incorporate high levels of EE, without specifying its plan or the program-level savings from doing so. This failure to provide detailed descriptions of programs and expected reductions in environmental impacts does not comply with A.A.C. R14-2-703(D)(14).

UNSE also provides no plan for reducing its environmental impacts related to air emissions, solid waste, and other environmental factors, and for reducing water consumption. This failure to provide a plan or description of impacts to air emissions, solid waste, and other environmental factors does not comply with A.A.C. R14-2-703(D)(17).

5. Environmental Impacts, Risks and Uncertainties

A.A.C. R14-2-703(E) requires analyses to identify and assess errors, risks, and uncertainties completed using methods such as sensitivity analysis and probabilistic analysis for the costs of compliance with existing and expected environmental regulations and any analysis by the load-serving entity in anticipation of potential new or enhanced environmental regulations. This section also requires the load serving entity to discuss means and measures for managing the errors, risks, and uncertainties.

A.A.C. R14-2-703(F)(3) requires the 15-year plan to address the adverse environmental impacts of power production. A.A.C. R14-2-703(F)(7) requires the plan to provide how the utility will effectively manage the uncertainty and risks associated with costs, environmental impacts, load forecasts, and other factors.

a) APS

APS provides lengthy discussion in the Section "Response to Rules Section E – Risk" regarding the regulations stated above.

APS provides responses to A.A.C. R14-2-703(F)(3) and A.A.C. R14-2-703(F)(7) in section "Response to Rules Section F – 2020 IRP."

b) AEPCO

AEPCO provided its response to the requirements of A.A.C. R14-2-703(E) and R14-2-703(F)(3) on August 26, 2020, in Docket No. E-00000V-19-0034.

c) TEP

Staff was unable to identify any location in its 2020 IRP where TEP discusses the costs of compliance with environmental regulations, or where TEP discusses efforts to assess risks or uncertainties related to these costs as required by A.A.C. R14-2-703(E).

TEP presents reductions in GHG emissions, localized NOx emissions in the Tucson area, and water consumption from generation in its discussion of its Preferred Portfolio, which complies with A.A.C. R14-2-703(F)(3). However, TEP does not discuss how its Preferred Portfolio, or how TEP otherwise, will effectively manage the uncertainty and risks associated with costs, environmental impacts, load forecasts, and other factors as required by A.A.C. R14-2-703(F)(7).

d) UNSE

Staff was unable to identify any location in its 2020 IRP where UNSE discusses the costs of compliance with environmental regulations, or where UNSE discusses efforts to assess risks or uncertainties related to these costs as required by A.A.C. R14-2-703(E).

Staff was unable to identify any location in its 2020 IRP where UNSE discusses its plan to reduce environmental impacts from power production. This lack of discussion does not comply with A.A.C. R14-2-703(F)(3). UNSE also does not discuss how its Preferred Portfolio, or how UNSE otherwise, will effectively manage the uncertainty and risks associated with costs, environmental impacts, load forecasts, and other factors as required by A.A.C. R14-2-703(F)(7).

> Staff concludes that the TEP and UNSE IRPs lacked sufficient supporting information required by A.A.C. R14-2-703(D)(1)(a), R14-2-703(D)(14), R14-2-703(D)(17), R14-2-703(E), and R14-2-703(F)(3). Staff recommends, TEP and UNSE include sufficient information in future IRPs regarding the environmental considerations, as required by the IRP Rules, discussed herein.

H. Portfolio Development

R14-2-703(D)(8) requires an LSE to submit a 15-year resource plan that considers a wide range of resources and promotes fuel and technology diversity within its portfolio. The portfolios that were constructed and presented in each 2020 IRP are summarized in Section III of this report.

The portfolios that were designed and presented in the 2020 IRPs allow APS, TEP, and UNSE to dramatically shift their resource mixes over the planning period. APS has committed to a 100 percent clean, carbon-free, resource mix by 2050. In addition, APS has committed to end the use of coal-fired generation by 2031. TEP states that, "given recent declines in the cost of zero-emission renewable technologies and the current outlook that these declines will continue, TEP's long-term strategy is now focused on completing the transition to 100 percent clean energy." UNSE states that it is committed to reaching a goal of supplying 50 percent of its energy to retail customers from renewable resources by 2035, while also remaining committed to reducing its carbon emissions.

Existing generation resources that emit carbon will have to be retired at some point in order for the LSEs to achieve the goals established in the 2020 IRPs. Therefore, the inclusion of a robust retirement analysis in future IRPs is necessary given these commitments. A robust retirement analysis can identify optimal resource retirement dates and quantify cost savings to ratepayers. Several stakeholders and Commissioners expressed questions and/or concerns with the identification of "must run" resources and the retirement dates presented by each LSE for various resources. The facts and circumstances around the operation of a utility's generation resources are not self-evident and should be fully explained and accompanied by supporting analysis so that the Commission and stakeholders understand the basis of an LSE's decision making.

Staff recommends the Commission order APS, TEP, and UNSE to include robust retirement analyses in future IRPs. Future IRPs should include a dedicated, comprehensive, analysis describing how the LSE evaluated the operations of its current resources, how retirement dates were selected, and why, and what the economic impact to ratepayers will be.

A comprehensive retirement analysis is also critical in the development of resource portfolios and the selection of an optimal Preferred Portfolio. Given the dramatic shift in the resource mix, robust portfolio development and analysis could be required in future IRPs submitted by APS, TEP, and UNSE.

Staff recognizes that there are many paths that can be taken in order to achieve significant carbon emission reductions. The analysis of a wide range of portfolios helps Commissioners and stakeholders understand the costs and benefits of achieving these reductions. In addition to understanding the costs and benefits, analyzing a wide range of portfolios ensures the optimal or least cost portfolio could be selected so that the goals of the LSE can be satisfied.

In this IRP process, APS presented three portfolios that it states will allow APS to achieve its goal of achieving 100 percent clean energy by 2050. TEP presented 15 portfolios to support its commitment and UNSE presented six portfolios. Overall, TEP's presentation was the most robust because it showed the impacts of various decisions that could be made in its pursuit to achieve significant emissions reductions. Moving forward, APS, TEP, and UNSE must include a wide range of portfolios in future IRPs in order to ensure the optimal or least cost portfolio will be selected.

Staff recommends the Commission order APS, TEP, and UNSE to include in future IRPs an analysis of, at minimum 10, resource portfolios that are designed to evaluate the range of resource procurement actions, and their respective cost and benefits, that can be taken to achieve the emissions reductions goals specified by each in its 2020 IRP. The analysis and presentation of these resource portfolios should be used to support APS, TEP, and UNSE's desire to achieve significant emissions reductions.

The LSEs state that clean and renewable energy technologies are continuing to decline in cost and that the adoption and use of these technologies can help lower costs to ratepayers. The costs and benefits of adopting a 100 percent reduction in emissions will need to be continuously evaluated and presented in future IRP proceedings. Therefore, Staff recommends the Commission order APS, TEP, and UNSE to include in future IRPs a comprehensive analysis that presents the costs and benefits of their emissions reduction commitments, compared to an approach absent these commitments, to their ratepayers.

Staff notes that the transition to a cleaner energy resource mix presents additional factors that should be considered in the development of resource portfolios and the LSE's IRP. Staff believes the following factors need to be considered and discussed more thoroughly: reliability risks and costs, resource adequacy risks and costs, overall costs to ratepayers, and direct and indirect environmental costs and benefits.

1. Reliability and Resource Adequacy

APS reports in its 2020 IRP that it studied reliability by using the AURORA Production Cost Model's Risk Analysis Functionality and employed a 15 percent planning reserve margin in the development of its future resource plans.[40] This is based on a Loss of Load Hours assumption of 24 hours over a ten-year period. APS states that the study simulated uncertainty with various load, solar, and wind shape sensitivities as well as random unit forced outage patterns for each iteration. The

[40] APS 2020 IRP at 48.

APS IRP states that the results of its Reserve Margin Study conclude that a 15 percent reserve margin is sufficient to meet APS's reliability requirements, but the IRP does not provide this Reserve Margin Study itself or excerpts from the study as quantitative evidence for this assertion. APS states that it applied the assumption of 15 percent reserve margin from its Reserve Margin Study in development of each of its portfolios.[41]

APS's 2020 IRP mentions resource adequacy in several places but does not provide any evidence or analysis clearly demonstrating how each of its resource portfolios meets the requirements of resource adequacy.

TEP states in its 2020 IRP that it utilized a 15 percent planning reserve margin assumption for its 2020 IRP and provides data in Tables 3 and 4 to demonstrate how its firm resources compare to its firm load obligations under this assumption.[42] TEP illustrates four resource adequacy metrics it uses in its IRP in Chart 7: 1) peak net load, 2) three-hour ramp in net load, 3) ten-minute ramp in net load, and 4) amount of over generation.[43] TEP states it conducted two resource adequacy studies for renewable energy resources, each evaluating six different scenarios of variable renewable energy penetration, provided a description of these studies and the results of the studies, and provided the conclusions it drew from the studies about the levels of renewable energy within its current resource capabilities.[44] TEP also provided these studies as appendices to its IRP. However, TEP's discussion of its various portfolios and its preferred portfolio do not evaluate or clearly describe the ability of each portfolio to meet the requirements of reliability and resource adequacy.

UNSE states in its 2020 IRP that it utilized a 15 percent planning reserve margin assumption and provides data in Tables 2 and 3 to demonstrate how its firm resources compare to its firm load obligations under this assumption.[45] UNSE also states it conducted a resource adequacy study for renewable energy resources, evaluating six different scenarios of variable renewable energy penetration, considering the same four criteria used by TEP in its own resource adequacy studies.[46] UNSE presents the results of the study, demonstrating the ability for UNSE to integrate and balance up to 50 percent renewable energy penetration.[47] UNSE also provides the study itself in an appendix to its IRP.

In future IRPs, the issue of resource adequacy should be discussed more thoroughly, and actions taken to address the issue of resource adequacy should be fully supported. On December 18, 2020, the Western Electricity Coordinating Council ("WECC") released a report titled "The Western Assessment of Resource

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[41] Id. at 129, 132.
[42] TEP 2020 IRP at 43-45.
[43] Id. at 52-54.
[44] Id. at 56-64.
[45] UNSE 2020 IRP at 35-37.
[46] Id. at 38-40.
[47] Id. at 40-41.

Adequacy Report"[48], in which WECC found that traditional methods of resource planning will not be adequate in the future due to the increasing variability on the system and if high levels of resource adequacy are to be preserved, resource planning methods and practices must adapt. Therefore, LSEs should analyze the resource adequacy implications of each of their scenarios, present the conclusions of this analysis and explanations of the methods used, and describe their efforts to adapt their resource adequacy analysis methods and practices to address increasing variability on the system.

The Western Assessment presents several planning recommendations to address these risks:

- "**Recommendation 1**: Planning entities and their regulatory authorities should consider moving away from a fixed planning reserve margin to a probabilistically determined margin. As variability grows, a dynamic planning reserve margin will better ensure resource adequacy for all hours."

- "**Recommendation 2**: Planning entities should consider not only how much additional capacity is needed to mitigate variability, but also the expected availability of the resource. Understanding the differences in resource type availability is crucial to performing resource adequacy studies."

- "**Recommendation 3**: Planning entities should coordinate their resource planning efforts on an interconnection-wide basis each year to help ensure they are not all relying on the same imports to maintain resource adequacy. This coordination will help subregions make assumptions about import availability in the context of the entire interconnection."

Staff recommends that APS, TEP, and UNSE include in future IRPs, a comprehensive discussion regarding how the LSE's methods for addressing resource adequacy are being adapted to address concerns with increasing variability on the bulk electric system.

2. Environmental Costs and Benefits

Given the commitments made by APS, TEP, and UNSE to reduce emissions, it would be beneficial for each LSE to further explore broad environmental costs and benefits of the portfolios presented in each IRP. R14-2-704(B) requires the Commission consider the environmental impacts of resource choices and alternatives, the degree to which the LSE considered all relevant

48 https://www.wecc.org/Administrative/Western%20Assessment%20of%20Resource%20Adequacy%20Report%2020201218.pdf

resources, risk, and uncertainties, and the degree to which the LSE's IRP is in the best interest of its customers in determining the public interest (R14-2-704(B)(7)-(9)). In addition, R14-2-703(D)(17) requires that the IRPs address the adverse environmental impacts of power production.

Environmental costs and benefits could, for example, relate to the recent drought declaration in the State of Arizona. Specifically, the environmental costs and risks associated with water use for power production could be explored further. If APS, TEP, and UNSE's clean energy commitments result in an overall reduction in the use of water in power generation, the associated costs and benefits should be included to support each utility's selection of a Preferred Portfolio and would be responsive to the requirements of A.A.C. R14-2-704(B)(7)-(9) and R14-2-703(D)(17). Therefore, APS, TEP, and UNSE should present information about the broader environmental impacts (e.g. societal costs of carbon emissions and water consumption associated with their resource choices) in their scenario analyses and IRPs so the Commission and stakeholders have the benefit of this information, as supported under the IRP Rules.

I. The Ascend Team's Recommendations

According to the Ascend team's report, "Ascend commends the LSEs on their IRP work, as they show credible pathways towards a dramatically lower carbon future while also maintaining reliability and managing costs. While there is still room for improvement, the quality of analysis and the boldness of vision is substantially improved from past IRPs. The IRPs show a transition from traditional coal and gas-based resources towards a more flexible cleaner portfolio anchored by renewables and storage."

Regarding the IRPs overall, the Ascend team's full set of recommendations are:

1. IRP Process

   a. Develop increasingly more inclusive, open, and transparent stakeholder processes.

   b. Include environmental and economic justice analysis as well as voices previously underrepresented in IRP stakeholder processes.

2. Resource Adequacy and Resiliency

   a. Include deeper and more robust analysis of resource adequacy with high renewables and storage.

   b. Include analysis of interconnected system risks between the gas and power systems.

c. Model correlations between weather and each of renewable generator output, forced outage rates, and transmission capacity.

d. Include analysis of climate impacts on future system reliability.

3. Resource Selection

a. Leverage optimized capacity expansion algorithms combined with "hand designed" portfolios and sensitivities.

b. Research and report out additional information on the uses for and economics around green hydrogen or other clean fuels, and how the existing gas thermal fleet could be repurposed to burn these fuels.

c. Include more research and modeling of non-lithium-ion storage options and long-duration storage.

4. DSM

a. Explore options for flexible demand through technologies such as smart thermostats, vehicle-to-grid, behind-the-meter solar and storage, and others on a level playing field with traditional supply side options.

b. Model linkages between electricity provision and building and vehicle electrification as a decarbonization strategy.

c. Incorporate more analysis of interval data for all demand side resources to better understand how their effects might shift demand impacts.

d. Include more scenario analysis, particularly for sources of load with high uncertainly (i.e., EV's).

5. Modeling Enhancements

a. Incorporate weather as a fundamental driver of power system operations and value.

b. Transition away from a "dispatch-to-load" concept towards one that incorporates further integration into Western energy markets. Incorporate hourly and sub-hourly prices from the Western EIM and a future Extended Day Ahead Mechanism.

c. Run stochastic studies to capture sensitivity to variations in weather, generation, and prices. Quantifying uncertainty is essential for risk management, portfolio balancing, and system reliability.

d. Assure long-term power price forecasts are aligned with changing market dynamics driven by renewable energy and storage deployment.

Staff recommends the Commission adopt the Ascend team's recommendations as detailed on pages 10 and 11 of its Redacted Revised Report dated August 12, 2021.

VI. STATE OF THE IRP RULES

A.A.C. R14-2-703 requires that the LSEs file the IRPs by April 1 of each even year. The filing requirements for the current IRP cycle have been established by Decision No. 76632, which also waived the relevant filing requirements in the IRP Rules. Furthermore, Decision No. 77696, ultimately required the 2020 IRPs be filed by August 26, 2020. Given these modifications to the filing requirements, the LSEs are unable to file the next IRPs, while utilizing a three-year development process, by April 1, 2022, which is the filing requirement for the next IRPs specified by A.A.C. R14-2-703. Staff recommends the Commission waive the filing requirements contained in A.A.C. R14-2-703 which require the LSEs to file the next IRPs by April 1, 2022.

Consistent with this IRP cycle and Commission Decision No. 76632, Staff concludes a three-year process should be utilized for the development of the next IRPs. Staff recommends the Commission require the next IRPs to be filed by August 1, 2023. Furthermore, Staff recommends the Commission order Staff to file in this docket, for the Commission's consideration, a recommended development timeline for the next IRPs within 90 days of the Commission's decision in this matter.

VII. CONCLUSIONS AND RECOMMENDATIONS

Staff reviewed the 2020 IRPs, Commissioner comments, stakeholder comments and recommendations, the Ascend team's analysis and recommendations, and other relevant filings made in the docket.

Based on its review, Staff concludes:

1. APS has a stated goal of delivering 100 percent clean, carbon-free, and affordable electricity to customers by 2050. In order to achieve the 2050 goal, APS plans to have a resource energy mix which leads to 65 percent clean energy with 45 percent of customers' electricity needs served by renewable energy by 2030. APS has a commitment to end the use of coal-fired generation by 2031. In its IRP, APS presents three portfolios which are: The Bridge, Shift, and Accelerate Portfolios. The portfolios include approximately 8,000, 9,500, and 12,000 MW of additional renewable capacity, respectively.

2. APS did not select a Preferred Portfolio, as required by R14-2-703(F)(1), and states that its Five-Year Action Plan is identical for all three portfolios. APS's 2020 – 2024 Action Plan includes 2,894 MW of the following

resource additions: 575 MW DSM, 193 MW of demand response, 408 MW of distributed energy, 962 MW of renewable energy, 750 MW of energy storage, and a 6 MW microgrid. After the Five-Year Action Plan period, each portfolio's resource additions differ dramatically.

3. In TEP's 2020 IRP, TEP states that TEP's long-term strategy is now focused on completing the transition to 100 percent clean energy. TEP developed and presented a total of 15 wide ranging portfolios in its 2020 IRP. TEP's Preferred Portfolio plans to reduce its reliance on coal generation and anticipates adding 450 MW of renewable capacity by 2021, to increase the total renewable energy portfolio to over 1,000 MW, or approximately 28 percent of TEP's energy portfolio, as well as increasing investment in energy storage. TEP's Preferred Portfolio will significantly increase its solar and wind power use as well as battery storage to serve approximately 70 percent of its retail load by 2035 with renewable resources and achieve 80 percent reduction in CO2 from 2005 levels.

4. TEP's Five-Year Action plan states it will complete the first phase of coal plant retirements when SJGS Unit 1 closes in June 2022. With that retirement, TEP will have retired 41 percent of its coal capacity since 2015. TEP will complete the build-out of planned solar and wind projects currently under contract or construction, which will double TEP's renewable energy output. TEP states it will initiate discussions with stakeholders regarding impacts due to the retirement of SGS Units 1 and 2. Furthermore, TEP will continue to implement cost-effective EE programs consistent with historical levels targeting 1.5 percent incremental energy savings over the prior year's retail load in each year through 2024. In addition, TEP is committed to procuring future resources through ASRFP based on specific, identified system needs. Finally, TEP states it will continue preparations for joining the CAISO Western EIM in April 2022.

5. UNSE states its 2020 IRP is designed to gradually divert the capacity mix from utilizing purchased power to predominantly utilizing self-reliant generation. Furthermore, UNSE states that it is committed to reaching a goal of supplying 50 percent of its energy to retail customers from renewable resources by 2035, while also remaining committed to reducing its carbon emissions. UNSE developed four resource portfolios in its IRP. UNSE's Preferred Portfolio has an energy mix consisting of increasing EE, a relatively consistent level of market purchases, increasing renewable energy, and consistent natural gas utilization, with a slight decrease in 2028. UNSE states that its Preferred Portfolio represents the lowest overall cost while still allowing them to reach the 50 percent goal by 2035. In addition, UNSE states this portfolio achieves the highest EE savings out of the evaluated portfolios.

6. UNSE's Five-Year Action Plan states it will continue to implement cost-effective EE programs consistent with historical levels targeting 1.5 percent incremental energy savings over the prior year's retail load in each year through 2024. UNSE will continue to procure market-based resources to meet its short-term capacity needs through 2024. In the interim, UNSE will explore other options through its future ASRFPs to acquire alternative resources if they are proven to be more cost-effective. UNSE states it is committed to procuring future resources through ASRFPs based on specific, identified system needs. UNSE anticipates issuing an ASRFP in 2022 or 2023. UNSE is conducting studies relating to the costs and benefits of actively participating in the CAISO Western EIM.

7. The 2020 IRP produced by APS, TEP and UNSE are reasonable and in the public interest, based upon the information available to Staff at the time this report was prepared, and the requirements set forth in A.A.C. R14-2-703(C), (D), (E), (F), (H) and A.A.C. R14-2-704(B).

8. AEPCO has satisfied the requirements of Decision No. 73884. AEPCO has continued to participate in the IRP process by filing whatever information, data, criteria, and studies it has used in its 15-year planning scenarios, without the necessity of having its IRP acknowledged by the Commission.

9. The LSEs have complied with Decision No. 76632, with the following exceptions:

    a. TEP and UNSE did not include a tabular representation that provides a breakdown by capacity and energy mix contributions for each portfolio that was analyzed, similar to Table ES-2 on Page 13 of APS's 2017 IRP.

    b. APS and TEP failed to discuss the costs and benefits of natural gas storage. TEP and UNSE also failed to discuss the risks of a lack of market area natural gas storage in Arizona and only briefly describe what would be required to develop efforts to develop natural gas storage without describing the status of any efforts to develop storage or lack thereof.

    c. APS provided discussion of various storage technologies and chemistries in its 2020 IRP in the titled "Energy Storage" section but provided no analysis of anticipated future energy storage cost declines of these technologies.

    d. Staff has requested that APS, TEP, and UNSE identify where this information can be found. Although this information is omitted from the 2020 IRPs, Staff believes the IRPs are reasonable and in the public interest.

10. Each 2020 IRP (except AEPCO's) meets the requirements of the ARER, the DRER, and the EE Standard.

11. The LSE load forecasts and IRPs were developed before the onset of the COVID-19 pandemic. As a result, the economic impacts of the pandemic, and the associated impact on future electric demand, could not have been adequately considered. It is unclear what changes to the Action Plans, if any, would be required based on these factors.

12. APS, TEP, and UNSE have included a reasonable range of technologies and associated costs in the 2020 IRPs.

13. The price of natural gas has both short- and long-term impacts on an LSE's resource procurement decisions. Given the expressed desire by APS, TEP, and UNSE, in the 2020 IRPs, to achieve significant carbon emissions reductions, the impact of a wide range of natural gas prices on resource procurement decisions needs to be thoroughly discussed in the IRP.

14. Forecasting the future cost of CO2 will continue to play an important role in understanding the costs and benefits of the various portfolios presented by each LSE in its IRP.

15. Participation in regional markets, such as the EIM, may provide benefits to ratepayers and result in more efficient resource procurement. Therefore, APS, TEP, and UNSE should improve future IRPs by analyzing to what extent regional market participation affects near- and long-term resource procurement actions.

16. The TEP and UNSE IRPs lack sufficient supporting information required by A.A.C. R14-2-703(D)(1)(a), R14-2-703(D)(14), R14-2-703(D)(17), R14-2-703(E), and R14-2-703(F)(3) (see Section V(G)(5) of the Staff Report for further discussion.

17. Existing generation resources that emit carbon will have to be retired at some point for the LSEs to achieve the goals established in the 2020 IRPs. Therefore, the inclusion of a robust retirement analysis in future IRPs is necessary given these commitments. A robust retirement analysis can identify optimal resource retirement dates and quantify cost savings to ratepayers. Several stakeholders and Commissioners expressed questions and/or concerns with the identification of "must run" resources and the retirement dates presented by each LSE for various resources. The facts and circumstances around the operation of a utility's generation resources are not self-evident and should be fully explained and accompanied by supporting analysis so that the Commission and stakeholders understand the basis of an LSE's decision making.

18. There are many paths that can be taken to achieve significant carbon emission reductions. The analysis of a wide range of portfolios helps Commissioners and stakeholders understand the costs and benefits of achieving these reductions. In addition to understanding the costs and benefits, analyzing a wide range of portfolios ensures the optimal or least cost portfolio will be selected so that the goals of the LSE can be satisfied.

19. The LSEs state that clean and renewable energy technologies are continuing to decline in cost and that the adoption and use of these technologies can help lower costs to ratepayers. The costs and benefits of adopting a 100 percent reduction in emissions will need to be continuously evaluated and presented in future IRP proceedings.

20. In future IRPs, the issue of resource adequacy should be discussed more thoroughly, and actions taken to address the issue of resource adequacy should be fully supported. On December 18, 2020, WECC released a report titled "The Western Assessment of Resource Adequacy Report", in which WECC found that traditional methods of resource planning will not be adequate in the future due to the increasing variability on the system and if high levels of resource adequacy are to be preserved, resource planning methods and practices must adapt. Therefore, LSEs should analyze the resource adequacy implications of each of their scenarios, present the conclusions of this analysis and explanations of the methods used, and describe their efforts to adapt their resource adequacy analysis methods and practices to address increasing variability on the system.

21. Given the commitments made by APS, TEP, and UNSE to reduce emissions, it would be beneficial for each LSE to further explore broad environmental costs and benefits of the portfolios presented in each IRP. R14-2-704(B) requires the Commission consider the environmental impacts of resource choices and alternatives, the degree to which the LSE considered all relevant resources, risk, and uncertainties, and the degree to which the LSE's IRP is in the best interest of its customers in determining the public interest (R14-2-704(B)(7)-(9)).

22. R14-2-703(D)(17) requires that the IRPs address the adverse environmental impacts of power production. Therefore, APS, TEP, and UNSE should present information about the broader environmental impacts (e.g., societal costs of carbon emissions and water consumption associated with their resource choices) in their scenario analyses and IRPs, so the Commission and stakeholders have the benefit of this information, as supported under the IRP Rules.

23. A.A.C. R14-2-703 requires that the LSEs file the IRPs by April 1 of each even year. The filing requirements for the current IRP cycle have been established by Decision No. 76632, which also waived the relevant filing

requirements in the IRP Rules. Furthermore, Decision No. 77696, ultimately required the 2020 IRPs be filed by August 26, 2020. Given these modifications to the filing requirements, the LSEs are unable to file the next IRPs, while utilizing a three-year development process, by April 1, 2022, which is the filing requirement for the next IRPs specified by A.A.C. R14-2-703.

24. Consistent with this IRP cycle and Commission Decision No. 76632, a three-year process should be utilized for the development of the next IRPs.

25. Ascend notes, "overall, the discussion of gas storage is brief and does not provide a detailed analysis of the arguments for or against developing natural gas storage in Arizona. Future IRPs should provide additional in-depth analysis related to system reliability and the risks/consequences of pipeline distribution." Furthermore, the Ascend team states, the recent "situation on the Texas grid in February 2021 highlighted the need for utilities to investigate the interconnected risks of the gas system failing to deliver adequate supply to power plants during periods of extreme weather. While Arizona is unlikely to experience the same cold weather conditions [as Texas did in February 2021], we recommend APS include in their next IRP an analysis of power system resiliency to extreme weather, including correlated risks to both the power and gas systems. Gas storage could potentially provide a hedge against natural gas supply interruptions and price shocks that would ultimately benefit APS customers."

26. Ascend notes, "policy and economic trends portend a decline in the demand for natural gas. As renewables generate more of the system energy, gas units' capacity factors will decline. At the same time, air source heat pumps are expected to reduce residential and commercial end use of natural gas. The implications of winding down the gas system as well as replacing natural gas with hydrogen and/or renewable natural gas should be studied by APS in the next IRP as part of the broader push for decarbonization." TEP and UNSE should also study these implications in future IRPs.

Staff recommends that:

1. APS, TEP, and UNSE include in future IRPs a comprehensive analysis of power system resiliency to extreme weather, including correlated risks to both the power and gas systems.

2. APS, TEP, and UNSE file, as a compliance item in this docket, updated Five-Year Action Plans that describe whether near-term resource selections have been impacted due to changes in the LSE's load forecast attributable to the COVID-19 pandemic within 90 days of the Commission's Decision in this matter.

3. APS, TEP, and UNSE include in future IRPs a dedicated section that explicitly discusses the LSE's natural gas price assumptions, the resulting impact of those assumptions on the LSE's short- and long-term resource procurement decisions, and the implications of declining natural gas usage as the LSEs shift resource mixes to achieve emissions reductions.

4. APS, TEP, and UNSE closely monitor federal legislation, and any other relevant legislation, related to a carbon tax and include in future IRPs a relevant discussion of the impacts of such legislation on the development of the IRP.

5. APS, TEP, and UNSE include in future IRPs a discussion of participation in regional markets and the effects of that participation on near- and long-term resource procurement actions.

6. TEP and UNSE include sufficient information in future IRPs regarding environmental considerations, as required by the IRP Rules.

7. The Commission order APS, TEP, and UNSE to include robust retirement analyses in future IRPs. Future IRPs should include a dedicated, comprehensive, analysis describing how the LSE evaluated the operations of its current resources, how retirement dates were selected, and why, and what the economic impact to ratepayers will be.

8. The Commission order APS, TEP, and UNSE to include in future IRPs an analysis of, at minimum 10, resource portfolios that are designed to evaluate the range of resource procurement actions, and their respective costs and benefits, that can be taken to achieve the emissions reductions goals specified by each in its 2020 IRP. The analysis and presentation of these resource portfolios should be used to support APS, TEP, and UNSE's desire to achieve significant emissions reductions.

9. The Commission order APS, TEP, and UNSE to include in future IRPs a comprehensive analysis that presents the costs and benefits of their emissions reduction commitments, compared to an approach absent these commitments, to their ratepayers.

10. APS, TEP, and UNSE include in future IRPs, a comprehensive discussion regarding how the LSE's methods for addressing resource adequacy are being adapted to address concerns with increasing variability on the bulk electric system.

11. The Commission adopt the Ascend team's recommendations as detailed on pages 10 and 11 of its Redacted Revised Report dated August 12, 2021.

12. The Commission waive the filing requirements contained in A.A.C. R14-2-703 which require the LSEs to file the next IRPs by April 1, 2022.

13. The Commission require the next IRPs to be filed by August 1, 2023.

14. The Commission order Staff to file in this docket, for the Commission's consideration, a recommended development timeline for the next IRPs within 90 days of the Commission's decision in this matter.

15. The Commission find that the 2020 IRPs are reasonable and in the public interest.

16. The Commission acknowledge the 2020 IRPs submitted by APS, TEP, and UNSE.

17. The Commission find that the information filed by AEPCO satisfies the requirements established in Decision Nos. 73884 and 75068.

VIII. ATTACHMENTS

Attached are Ascend Analytics August 12, 2021, Redacted Revised Report and September 21, 2021, Revised Report.

ATTACHMENT

Docket No. E-00000V-19-0034

Ascend Analytics

Better models. Better decisions.

REDACTED

REVISED

REPORT

ARIZONA UTILITY INTEGRATED RESOURCE PLAN REVIEW

PREPARED FOR:

ARIZONA CORPORATION COMMISSION

SEAL OF THE ARIZONA CORPORATION COMMISSION

DITAT DEUS

1912

AUGUST 12, 2021

Authors:

Ascend Analytics

David Millar, Director of Resource Planning Consulting
Anthony Boukarim, Senior Consultant
Zach Brode, Senior Energy Analyst
Brandon Mauch, Manager, Resource Planning Consulting Analytics
Brent Nelson, Manager, Market Analysis and Forecasting

Verdant Associates

Colin Elliot, Senior Principal Consultant
William Marin, Co-Founder
Jean Shelton, Co-Founder

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Executive Summary

The Arizona Corporation Commission ("ACC" or "Commission") engaged Ascend Analytics ("Ascend") and Verdant Associates ("Verdant") (combined "the Ascend team") to provide an independent review of the 2020 Integrated Resource Plans ("IRPs") filed by Arizona Public Service ("APS"), Tucson Electric Power ("TEP") and UNS Electric ("UNSE") (together referred to as load serving entities "LSEs" or "Utilities"). Additionally, the ACC asked the Ascend team to work with the LSEs to develop cost estimates for adopting the proposed Energy Rules versus a hypothetical "least-cost" pathway.

ES. 1 RESULTS OF ENERGY RULES VERSUS LEAST COST ANALYSIS

The Ascend team worked with each utility to develop expansion plans through 2050 in order to calculate the cost impacts of complying with the proposed Energy Rules. The Energy Rules initially required a 100% reduction in greenhouse gas ("GHG") emissions by 2050. Subsequent action by the ACC reduced the requirement to 80% by 2050 and 100% by 2070. The utilities modeled the following cases through 2050.

- 80% clean energy by 2050
- 100% clean energy by 2050
- "Least-cost" portfolio through 2050

The 2020 IRPs modeled their power systems only through 2035, therefore Ascend worked with each utility to develop expansion plans through 2050 that met the GHG reduction requirements of the Energy Rules. By necessity of the short time allotted for this analysis, the utilities developed expansion plans with their IRP portfolios as a starting point. Only minor modifications were necessary to the TEP and APS expansion plans because their IRP plans put them on track to meet the Energy Rules already. The "least-cost" portfolio was assumed to be one in which natural gas generation remained the primary resource for incremental capacity albeit with additional renewable energy added to the system to cover much of the additional energy needs. None of the expansion plans were developed using capacity expansion algorithms but were instead "hand-designed." Regardless of whether these portfolios could be more "optimal," they are directionally instructive as to some of the cost tradeoffs between a more traditional capacity expansion approach and a decarbonization pathway.

In addition to the core cases, the utilities ran sensitivity cases using Ascend's inputs for power and gas prices as well as Ascend assumptions on effective load carrying capabilities of renewables and storage, for a total of six runs each. All modeling was performed in the utility's licensed production cost model Aurora by Energy Exemplar by the utilities themselves rather than by Ascend Analytics. At the time of this report writing, the UNSE analysis remains ongoing. Ascend will file a supplemental report showing the results of that analysis.

Results

Ascend used the modeling results to calculate differences in revenue requirements (cost of supply to serve load and incremental transmission revenue requirements), average rate impacts (revenue requirements divided by retail sales), and average monthly residential bill impacts (rate impacts multiplied by average monthly energy consumption). Table ES -1a, b and c show the results of the analysis for APS:

ES-1a: Revenue Requirements ($M)

	2025	2030	2035	2040	2050
100% Clean	2,714 - 2,865	3,419 - 3,472	3,831 - 3,969	4,294 - 4,738	7,342 - 7,952
80% Clean	2,714 - 2,865	3,419 - 3,472	3,832 - 3,969	3,919 - 4,410	5,657 - 6,193
Least Cost	2,613 - 2,796	3,118 - 3,164	3,272 - 3,436	3,307 - 3,789	4,650 - 5,545
Difference (100% Clean – Least Cost)	69 - 100	301 - 308	533 - 560	949 - 987	2,407 - 2,692
Difference (80% Clean – Least Cost)	69 - 100	301 - 308	533 - 560	612 - 621	648 - 1,008
% Difference (100% Clean – Least Cost)	2% - 4%	10% - 11%	16% - 17%	25% - 30%	43% - 58%
% Difference (80% Clean – Least Cost)	2% - 4%	10% - 11%	16% - 17%	16% - 19%	12% - 22%

ES-1b: Average Rate Impacts ($/kWh)

	2025	2030	2035	2040	2050
100% Clean	0.079 - 0.083	0.088 - 0.090	0.091 - 0.094	0.094 - 0.104	0.136 - 0.147
80% Clean	0.079 - 0.083	0.088 - 0.090	0.091 - 0.094	0.086 - 0.097	0.105 - 0.115
Least Cost	0.074 - 0.079	0.077 - 0.078	0.073 - 0.077	0.067 - 0.077	0.076 - 0.091
Difference (100% Clean – Least Cost)	0.0036 - 0.0044	0.0109 - 0.0111	0.0175 - 0.0179	0.0273 - 0.0274	0.0563 - 0.0597
Difference (80% Clean – Least Cost)	0.0036 - 0.0044	0.0109 - 0.0111	0.0175 - 0.0179	0.0191 - 0.0202	0.0237 - 0.0285
% Difference (100% Clean – Least Cost)	4% - 6%	14% - 15%	23% - 24%	36% - 41%	62% - 78%
% Difference (80% Clean – Least Cost)	4% - 6%	14% - 15%	23% - 24%	26% - 29%	26% - 37%

ES-1c: Average Monthly Residential Bill Impacts ($)

	2025	2030	2035	2040	2050
100% Clean	85.93 - 90.73	94.56 - 96.04	95.66 - 99.09	96.78 - 106.78	134.14 - 145.29
80% Clean	85.93 -90.73	94.56 - 96.04	95.66 - 99.09	88.33 - 99.39	103.36 - 113.15
Least Cost	82.75 - 88.53	86.23 - 87.52	81.68 - 85.78	74.54 - 85.39	84.96 - 101.31
Difference (100% Clean – Least Cost)	2.20 - 3.18	8.33 - 8.52	13.32 - 13.98	21.38 - 22.24	43.98 - 49.19
Difference (80% Clean – Least Cost)	2.20 - 3.18	8.33 - 8.52	13.32 -13.99	13.79 - 14.00	11.84 - 18.41
% Difference (100% Clean – Least Cost)	2% - 4%	10% - 11%	16% - 17%	25% - 30%	43% - 58%
% Difference (80% Clean – Least Cost)	2% - 4%	10% - 11%	16% - 17%	16% - 19%	12% - 22%

Table ES – 2a, b, and c show the results of the analysis for TEP:

ES-2a: Revenue Requirements ($M)

	2025	2030	2035	2040	2050
100% Clean	1,223 - 1,226	1,410 - 1,484	1,540 - 1,650	1,713 - 2,033	2,067 - 3,085
80% Clean	1,223 - 1,224	1,409 - 1,484	1,540 - 1,650	1,687 - 1,978	1,894 - 2,864
Least Cost	1,223 - 1,224	1,409 - 1,424	1,518 - 1,540	1,669 - 1,779	1,874 - 2,365
Difference (100% Clean – Least Cost)	0 - 2	1 - 60	1 - 132	44 - 254	193 - 720
Difference (80% Clean – Least Cost)	0 - 0	0 - 60	0 - 132	18 - 199	19 - 499
% Difference (100% Clean – Least Cost)	0% - 1%	0% - 4%	0% - 9%	3% - 14%	10% - 30%
% Difference (80% Clean – Least Cost)	0% - 1%	0% - 4%	0% - 9%	1% - 11%	1% - 21%

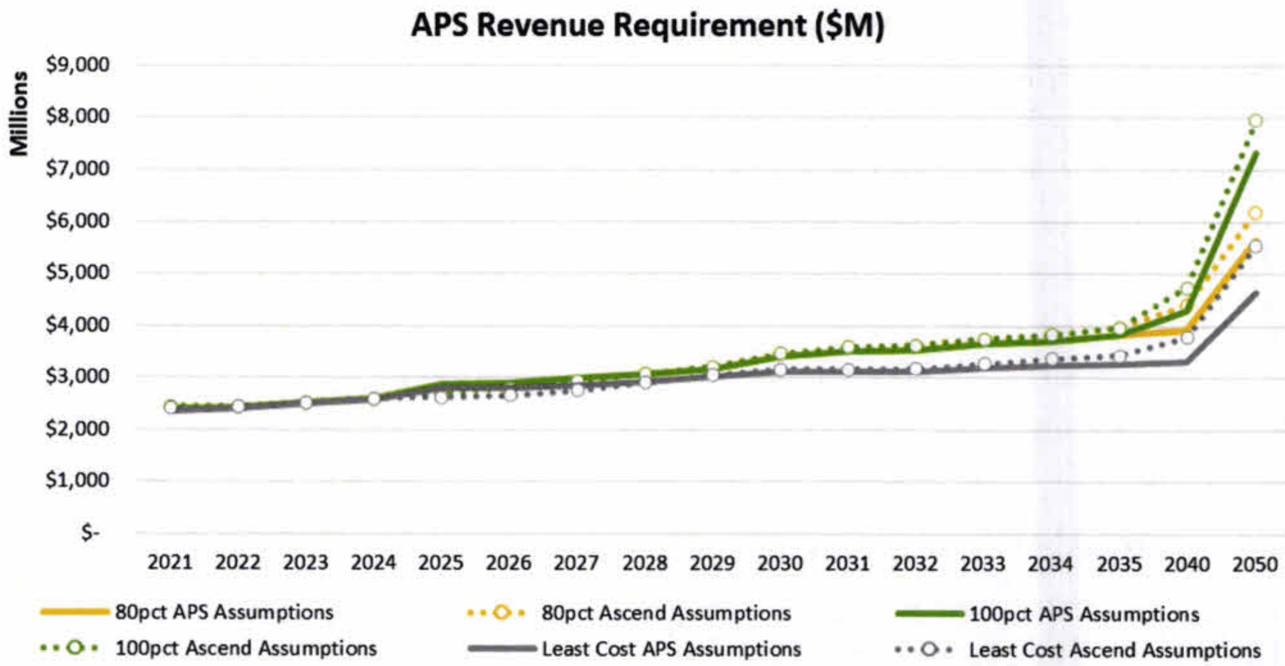
ES-2b: Average Rate Impacts ($/kWh)

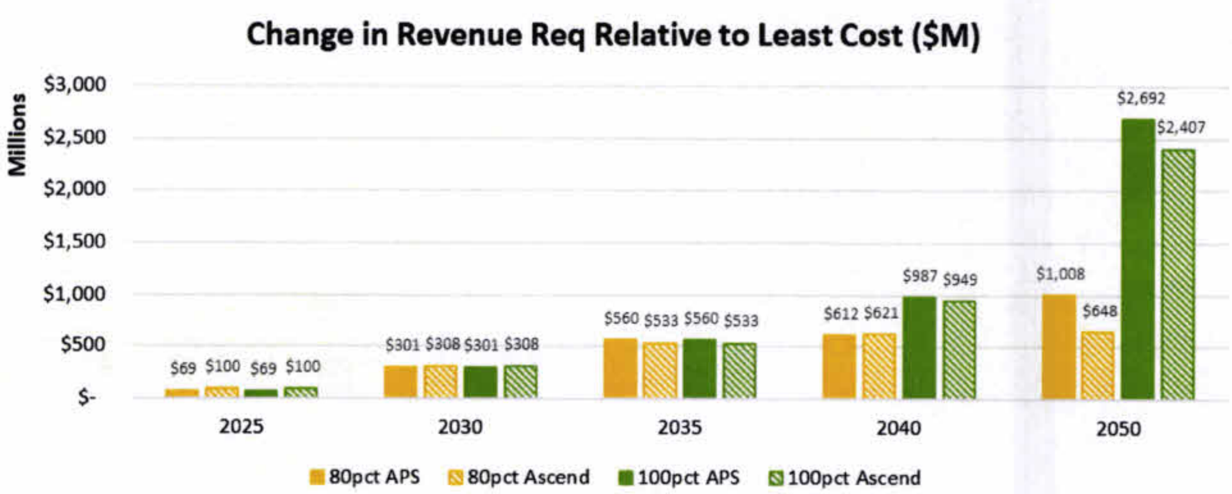
	2025	2030	2035	2040	2050
100% Clean	0.135 - 0.136	0.141 - 0.148	0.145 - 0.155	0.152 - 0.181	0.167 - 0.249
80% Clean	0.135 - 0.135	0.141 - 0.148	0.145 - 0.155	0.150 - 0.176	0.153 - 0.231
Least Cost	0.135 - 0.135	0.141 - 0.142	0.143 - 0.145	0.148 - 0.158	0.152 - 0.191
Difference (100% Clean – Least Cost)	0.0000 - 0.0002	0.0001 - 0.0060	0.0001 - 0.0124	0.0039 - 0.0226	0.0156 - 0.0582
Difference (80% Clean – Least Cost)	0.0000 - 0.0000	0.0000 - 0.0060	0.0000 - 0.0124	0.0016 - 0.0177	0.0016 - 0.0403
% Difference (100% Clean – Least Cost)	0% - 1%	0% - 4%	0% - 9%	3% - 14%	10% - 30%
% Difference (80% Clean – Least Cost)	0% - 1%	0% - 4%	0% - 9%	1% - 11%	1% - 21%

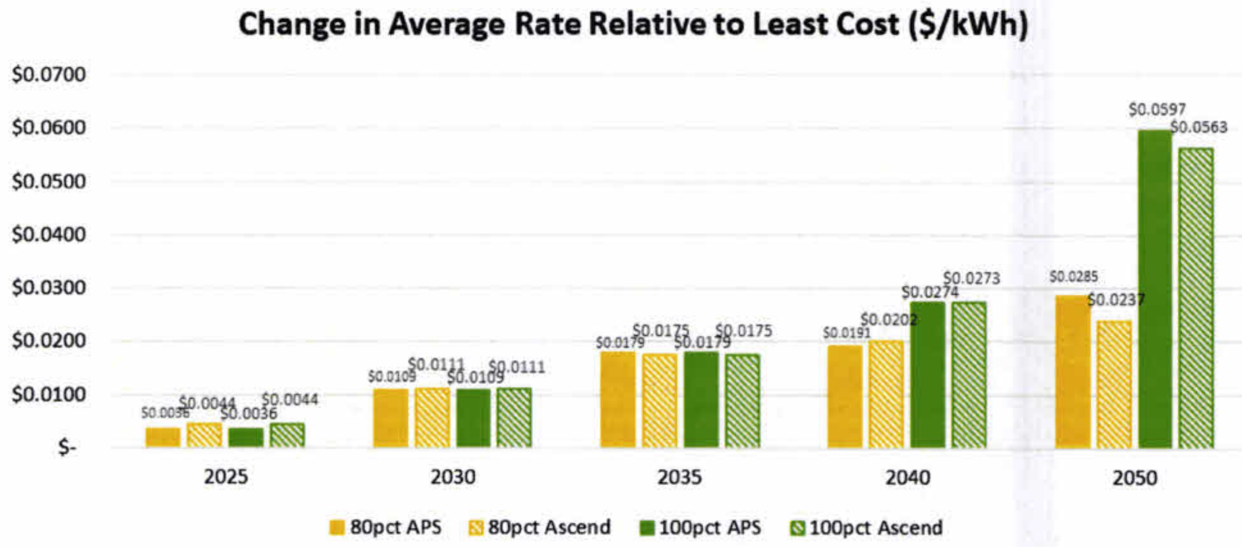
ES-2c: Average Monthly Residential Bill Impacts ($)

	2025	2030	2035	2040	2050
100% Clean	135.32 - 135.64	140.97 - 148.40	145.09 - 155.40	152.31 - 180.73	167.14 - 249.38
80% Clean	135.29 - 135.42	140.86 - 148.38	145.02 - 155.40	149.99 - 175.82	153.09 - 231.49
Least Cost	135.29 - 135.43	140.86 - 142.41	143.00 - 145.02	148.41 - 158.16	151.53 - 191.15
Difference (100% Clean – Least Cost)	0.03 - 0.21	0.11 - 5.99	0.07 - 12.40	3.90 - 22.57	15.61 - 58.23
Difference (80% Clean – Least Cost)	0.00 - 0.00	0.00 - 5.97	0.00 - 12.40	1.58 - 17.66	1.56 - 40.33
% Difference (100% Clean – Least Cost)	0% - 1%	0% - 4%	0% - 9%	3% - 14%	10% - 30%
% Difference (80% Clean – Least Cost)	0% - 1%	0% - 4%	0% - 9%	1% - 11%	1% - 21%

Note that the revenue requirements and average rates should not be compared between APS and TEP. The revenue requirement for TEP is all-in and includes the costs associated with distribution systems while APS includes only generation and transmission costs. However, distribution costs are considered the same across the different cases and thus the interest lies in the incremental cost relative to the "least cost" scenario. Also, the customer usage assumptions are slightly different between the two utilities causing the average rates to have different base lines.






Change in Average Rate Relative to Least Cost ($/kWh)
$0.0700
$0.0600
$0.0500
$0.0400
$0.0300
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$-
2025
2030
2035
2040
2050
$0.0036
$0.0044
$0.0036
$0.0044
$0.0109
$0.0111
$0.0109
$0.0111
$0.0179
$0.0175
$0.0179
$0.0175
$0.0191
$0.0202
$0.0274
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$0.0597
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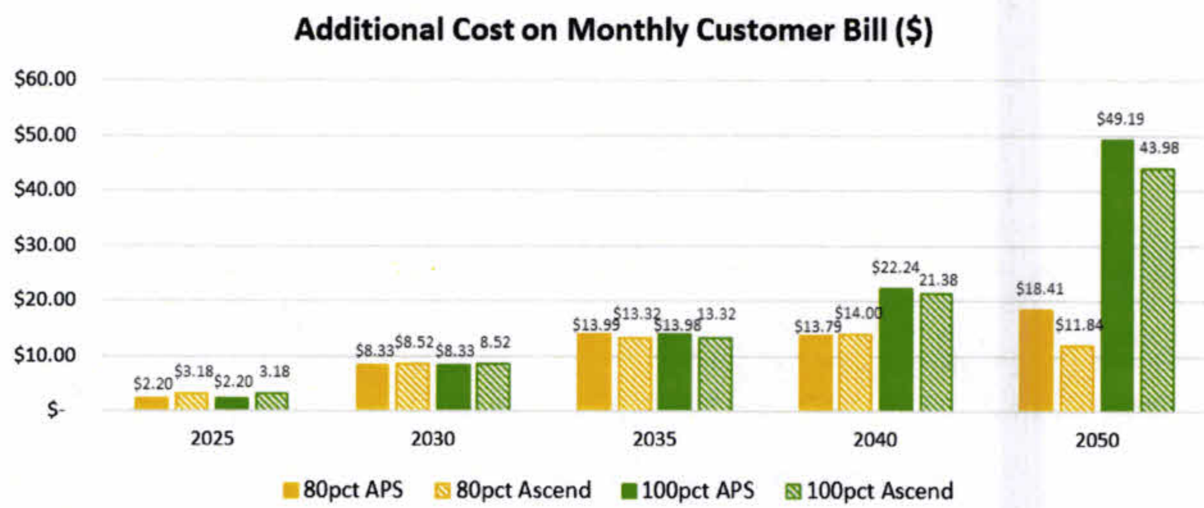
80pct APS
80pct Ascend
100pct APS
100pct Ascend


Additional Cost on Monthly Customer Bill ($)
$60.00
$50.00
$40.00
$30.00
$20.00
$10.00
$-
2025
2030
2035
2040
2050
$2.20
$3.18
$2.20
3.18
$8.33
$8.52
$8.33
8.52
$13.99
$13.32
$13.98
13.32
$13.79
$14.00
$22.24
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$11.84
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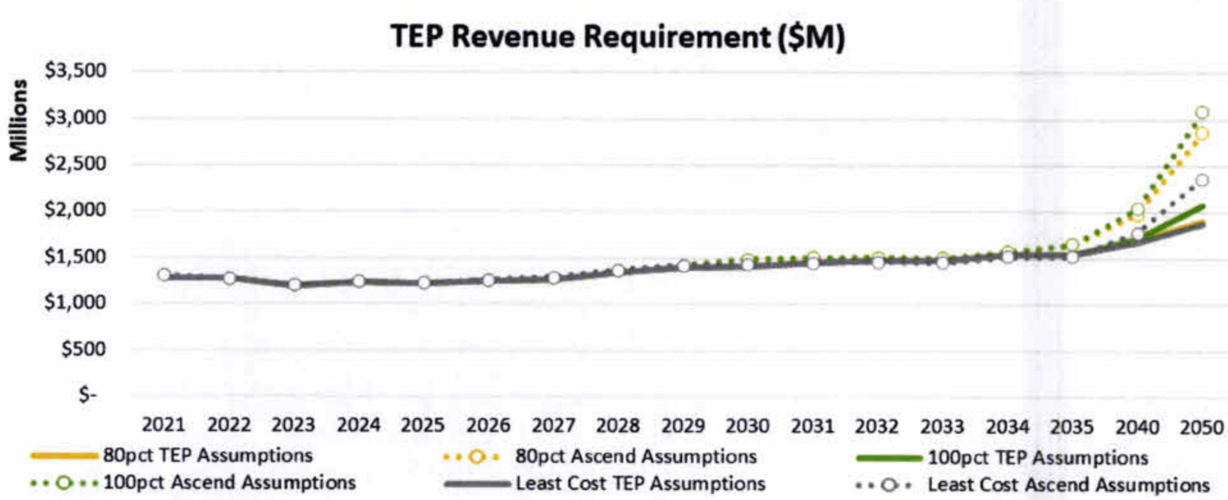
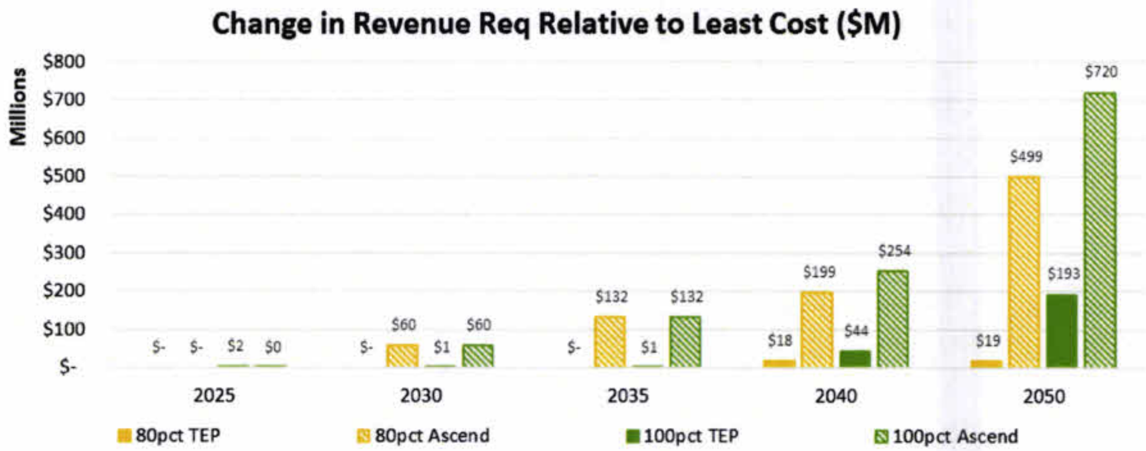
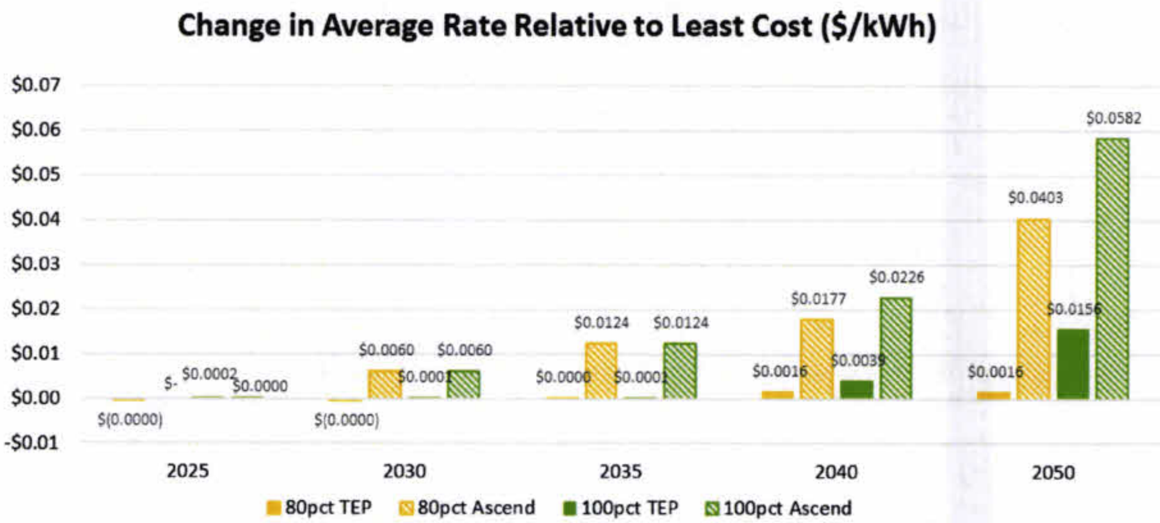
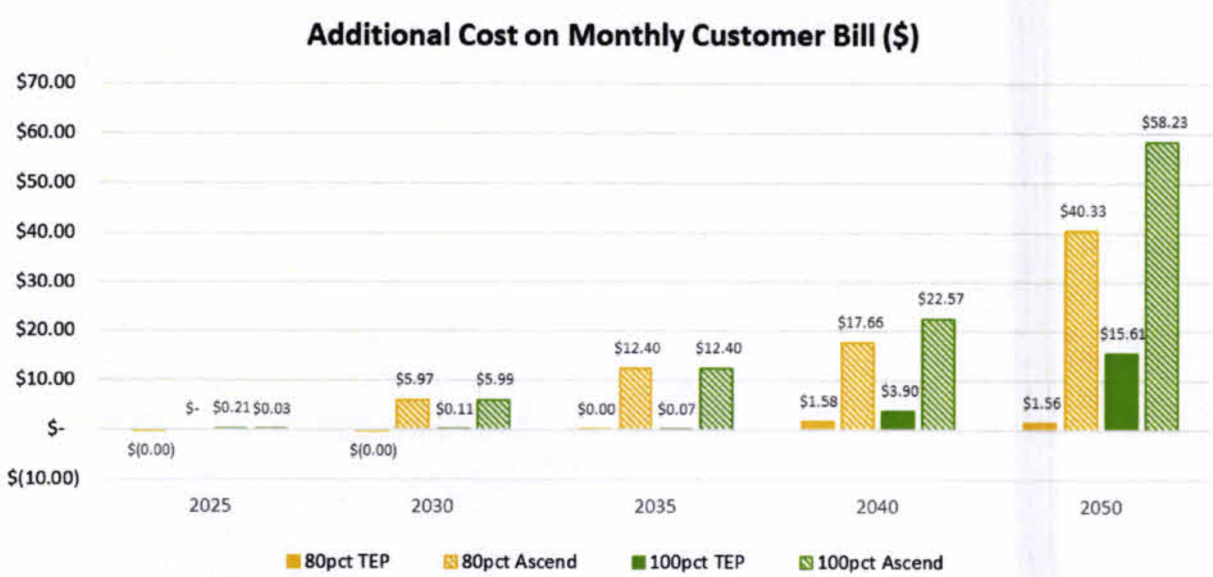
43.98
80pct APS
80pct Ascend
100pct APS
100pct Ascend


TEP Revenue Requirement ($M)
Millions
$3,500
$3,000
$2,500
$2,000
$1,500
$1,000
$500
$-
2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2040 2050
80pct TEP Assumptions
80pct Ascend Assumptions
100pct TEP Assumptions
100pct Ascend Assumptions
Least Cost TEP Assumptions
Least Cost Ascend Assumptions


Change in Revenue Req Relative to Least Cost ($M)
Millions
$800
$700
$600
$500
$400
$300
$200
$100
$-
$- $- $2 $0
$- $60 $1 $60
$- $132 $1 $132
$18 $199 $44 $254
$19 $499 $193 $720
2025
2030
2035
2040
2050
80pct TEP
80pct Ascend
100pct TEP
100pct Ascend


Change in Average Rate Relative to Least Cost ($/kWh)
$0.07
$0.06
$0.05
$0.04
$0.03
$0.02
$0.01
$0.00
-$0.01
$(0.0000) $- $0.0002 $0.0000
$(0.0000) $0.0060 $0.0001 $0.0060
$0.0000 $0.0124 $0.0001 $0.0124
$0.0016 $0.0177 $0.0039 $0.0226
$0.0016 $0.0403 $0.0156 $0.0582
2025
2030
2035
2040
2050
80pct TEP
80pct Ascend
100pct TEP
100pct Ascend


Additional Cost on Monthly Customer Bill ($)
$70.00
$60.00
$50.00
$40.00
$30.00
$20.00
$10.00
$-
$(10.00)
$(0.00) $- $0.21 $0.03
$(0.00) $5.97 $0.11 $5.99
$0.00 $12.40 $0.07 $12.40
$1.58 $17.66 $3.90 $22.57
$1.56 $40.33 $15.61 $58.23
2025
2030
2035
2040
2050
80pct TEP
80pct Ascend
100pct TEP
100pct Ascend

Discussion:

Ascend's key take-aways of the analysis are as follows:

- **The results show low to moderate cost increases in revenue requirements, rates, and bills in both 80% and 100% pathways.**
  - In the APS 80% case, residential customers would pay approximately an additional $14 per month by 2035, between $14 per month by 2040 and $12 - $18 per month in 2050. When going to 100%, these values remain the same through 2035. By 2040 the Energy Rules case would cost an additional $22 per month and an additional $44 - $49 per month by 2050. Note that these dollars are nominal. In 2050 dollars, $50 is equivalent to about $25 in today's dollars assuming a 2.5% inflation rate.
  - In the TEP 80% case, residential customers would pay an additional $0 - $12 per month in 2035, $2 - $18 per month by 2040, and $2 - $40 per month by 2050. In the 100% case, by 2035 TEP customers would pay an additional $0 - $12 per month, $4 - $23 per month in 2040, and $16 - $58 per month in 2050.
- The most significant cost increases would occur between the 2040 and 2050 time frame when the utilities achieve between 80 to 100% clean energy. This is due to the need to convert natural gas fired power plants to burn expensive green hydrogen and add longer duration storage (8 to 100 hours) required for capacity and reliability.
- The wider uncertainty band in the TEP results is indicative of differing assumptions on the load carrying capability of renewables and storage. Ascend predicts a faster decline in the ability of solar, wind, and 4-hour storage to provide system reliability than TEP, therefore the Ascend assumptions for TEP's portfolios includes additional capacity and additional cost. TEP also has more aggressive assumptions for decline in clean energy technology costs than what is published in the NREL ATB database.
- Achieving at least 80% clean energy can be reliable and cost-effective with today's technology costs and capabilities. Cost-effectively achieving higher than 80% clean energy while maintaining reliability requires innovation in clean energy technologies, such as green hydrogen, long-duration storage, or advanced nuclear.

Study Limitations

As with any very long-range study, results in the distant future must be taken somewhat with a grain of salt. We have little information as to what technologies will be available or how exactly the power system will evolve. We believe these results are directionally consistent with an emerging consensus[1] that decarbonizing the power sector until at least 80% - 90% clean energy is achievable and cost-effective with today's technology over a timespan covering the next two decades.

Some limitations include:

[1] For example see NREL study on reaching 100% clean electricity https://www.nrel.gov/news/program/2021/the-challenge-of-the-last-few-percent-quantifying-the-costs-and-emissions-benefits-of-100-renewables.html

- The studies only compare three discrete scenarios, none of which were optimized. A more thorough study would leverage capacity expansion algorithms as well as discrete sensitivities to test key assumptions.
- This study was not paired with loss of load probability analysis. We cannot say with confidence that these portfolios are reliable without conducting an independent reliability analysis.
- This study was performed deterministically, meaning we do not analytically capture meaningful uncertainty driven by weather as a fundamental driver of load, renewable output, forced outages, and gas and power price dynamics. A deterministic result only shows a single view of the world versus a distribution of possible outcomes.
- Study is completed with perfect foresight (i.e. model "sees" all prices and optimizes dispatch perfectly) at the hourly level (as opposed to 5-minute intervals), which fundamentally undervalues flexible resources such as batteries in the context of participation in the Western Energy Imbalance Market ("EIM").

Analytical studies such as this one, provide important insights into the mechanics of complex systems including how changes in assumptions about future uncertainties would impact the outcomes. The following table highlights key assumptions and how results would be affected if they were more or less than we believe today.

Table ES – 3: Understanding the Impacts of Key Uncertainties

Assumption	What would cause costs to be less than expected?	What would cause costs to be more than expected?
Effective load carrying capability (ELCC)	ELCC of wind, solar, and batteries are more than we expect, potentially as a function of portfolio effects and geographic diversity.	ELCC of wind, solar, and batteries are less than we expect, potentially as a function of strong correlation in weather regimes on renewable output.
Technology types and costs	If innovation makes storage dramatically more cost-effective than we expect costs of decarbonization would decrease.	If future technologies do not decline as we expect, then costs to decarbonize would be higher than shown here.
Climate change	Climate impacts are more moderate than we expect, meaning less need to build peaking capacity for heat storms.	Climate impacts are worse than we expect, therefore additional capacity is needed to maintain reliability during more frequent and longer heat storms.
Market structure	If LSEs join a regional RTO, the cost of decarbonization due to better coordination of resources across the West.	Not applicable.
Transmission	Federal spending and permitting reforms support additional transmission that unlocks more low-cost renewable energy. Higher adoption and targeted deployment of distribution sited storage and distributed energy resources reduces the need for transmission spending.	No federal spending or permitting reform. Low adoption/sub-optimal deployment of distributed energy resources.

Recommendations on Next Steps

Should the ACC feel more analysis would be beneficial to support regulatory policy making, Ascend makes the following recommendations:

1. Commission a study using an independent analytical firm (and/or national lab, ASU, etc.) to model pathways to 100% clean energy by 2050.
2. Make sure to hire an analyst that uses best-in-class "HD PCMs." There are several that have been developed by various modeling firms.
3. Include other sectors in the analysis, such as transportation and building electrification.
4. Investigate both supply and demand-side solutions.
5. Utilize capacity expansion and scenario design.
6. Include a stakeholder engagement process.
7. Make sure to include reliability analysis, resiliency, and climate impacts.
8. Allot a sufficient amount of time and resources to make the analysis robust and meaningful. Nine months to one year is typical.

ES. 2 REVIEWS OF IRPS AND SUMMARY OF RECOMMENDATIONS FOR FUTURE IRPS

Overall, Ascend commends the LSEs on their IRP work, as they show credible pathways towards a dramatically lower carbon future while also maintaining reliability and managing costs. While there is still room for improvement, the quality of analysis and the boldness of vision is substantially improved from past IRPs. The IRPs show a transition from traditional coal and gas-based resources towards a more flexible cleaner portfolio anchored by renewables and storage.

In Section 2, we review compliance of the IRPs with Decision No. 76632, which directed the LSEs to include in their IRPs several elements such as natural gas storage, battery storage, low or no-load growth, only 20% additional thermal resources, and clean energy portfolios. The LSEs are largely compliant with this Decision, although the treatment of some of these topics could have been more in depth and we recommend further analysis in subsequent IRPs.

Section 3 provides a critical review of the IRPs with respect to modern planning principles, including reliability, equity, environmental performance, and minimizing cost. We also review the quality of the analytical work and recommend several improvements that can be made to enhance their analysis with "high-definition" production cost and reliability modeling. Regarding the IRPs overall, Ascend's full set of recommendations are as follows:

1. IRP Process

a) Develop increasingly more inclusive, open, and transparent stakeholder processes.
b) Include environmental and economic justice analysis as well as voices previously underrepresented in IRP stakeholder processes.

2. Resource Adequacy and Resiliency

a) Include deeper and more robust analysis of resource adequacy with high renewables and storage.
b) Include analysis of interconnected system risks between the gas and power systems.

c) Model correlations between weather and each of renewable generator output, forced outage rates, and transmission capacity.
d) Include analysis of climate impacts on future system reliability.

3. Resource Selection

a) Leverage optimized capacity expansion algorithms combined with "hand designed" portfolios and sensitivities.
b) Research and report out additional information on the uses for and economics around green hydrogen or other clean fuels, and how the existing gas thermal fleet could be repurposed to burn these fuels.
c) Include more research and modeling of non-lithium ion storage options and long-duration storage.

4. Demand Side Management (DSM)

a) Explore options for flexible demand through technologies such as smart thermostats, vehicle-to-grid, behind-the-meter solar and storage, and others on a level playing field with traditional supply side options.
b) Model linkages between electricity provision and building and vehicle electrification as a decarbonization strategy.
c) Incorporate more analysis of interval data for all demand side resources to better understand how their effects might shift demand impacts.
d) Include more scenario analysis, particularly for sources of load with high uncertainly (i.e. electric vehicles).

5. Modeling Enhancements

a) Incorporate weather as a fundamental driver of power system operations and value.
b) Transition away from a "dispatch-to-load" concept towards one that incorporates further integration into Western energy markets. Incorporate hourly and sub-hourly prices from the Western Energy Imbalance Market and a future Extended Day Ahead Mechanism.
c) Run stochastic studies to capture sensitivity to variations in weather, generation, and prices. Quantifying uncertainty is essential for risk management, portfolio balancing, and system reliability.
d) Assure long-term power price forecasts are aligned with changing market dynamics driven by renewable energy and storage deployment.

Chairwoman's Letter on "Must-Run" designation for Four Corners and Solana PPA

Section 3.3.3 shows a response to the ACC Chairwoman's letter dated July 27, 2021. In it we find the following conclusions regarding the "must-run" status of Four Corners and Solana:

- APS should have explicitly shown a scenario in which Four Corners retired earlier than 2031. We do not know if retiring Four Corners early would be least-cost without model runs of that option. Regardless of whether it is the "least-cost" pathway, APS believes that an earlier retirement would be risky from a system reliability perspective and would be difficult to terminate the coal contract prior to expiration in 2031 because it would require agreement from all owners of the plant. These concerns and difficulties are valid, nonetheless with many stakeholders interested in understanding the options around early retirement, APS could have explicitly shown this scenario and analytically demonstrated with loss of load probability studies as well as qualitative reasoning why this would not be an acceptable or prudent option at this time.

- The Solana power purchase agreement is a contract for offtake of renewable energy from the Solana concentrating solar generation station. The contract was approved in 2008 prior to a rapid decrease in the cost of solar photovoltaic technology. APS only pays for energy delivered even if that energy costs significantly above market. While in hindsight the contract appears to be a bad deal for APS ratepayers, we can only judge decisions based on the information known at the time. From a modeling perspective, the contract should be considered "must-take" because it is a renewable PPA with no fuel cost and APS is contractually obligated to take the energy as it is generated.

1 Introduction

The Arizona Corporation Commission (ACC or "Commission) engaged Ascend Analytics (Ascend) and Verdant Associates (Verdant) (combined "the Ascend team") to provide an independent review of the 2020 Integrated Resource Plans (IRPs) filed by the three regulated utilities (together referred to as load serving entities or "LSEs"). Additionally, the ACC asked the Ascend team to work with the LSEs to develop cost estimates for adopting the proposed Energy Rules versus a hypothetical "least-cost" pathway.

Ascend, a leading energy modeling software and consulting services firm based in Boulder Colorado, is focused on developing and leveraging powerful analytics solutions for use in modern resource planning and decision analysis amidst a rapidly changing energy system. Based in Berkeley, California, Verdant is home to leading experts in the fields of demand-side energy resources such as energy efficiency, demand response, and distributed energy resources as well as load forecasting.

This report summarizes our findings. It includes:

- A review of the compliance with Commission Decision 76632 (Section 2)
- A review of the IRPs with respect to assumptions and inputs as well as industry best modeling practices (Section 3)
- A modeling exercise executed in partnership with the LSEs to quantify costs of compliance with the new proposed energy rules relative to a least-cost case (Section 4)

1.1 REGULATORY BACKGROUND

The ACC's Resource Planning and Procurement Rules ("IRP Rules") were adopted on February 3, 1989, and amended by final rulemaking, effective December 20, 2010. The IRP Rules can be found in Arizona Administrative Code Title 14 Chapter 2 Article 7 Resource Planning and Procurement.1 *A.A.C. R14-2-701 through R14-2-706.* The 2010 amendment updated the original IRP rules to include the environmental impacts of resources and procurement costs.

The IRP Rules require that 15-year IRPs be prepared and submitted by LSEs to the Commission in each evenly numbered year on April 1. The IRP Rules define a "load-serving entity" as "...a public service corporation that provides electricity generation service and operates or owns, in whole or in part, a generating facility or facilities with a capacity of at least 50 megawatts combined."

The following Commission regulated electric utilities are classified as LSEs:

- Arizona Public Service Company ("APS"),
- Tucson Electric Power Company ("TEP"),
- UNS Electric, Inc. ("UNS Electric"), and
- Arizona Electric Power Cooperative ("AEPCO").

Pursuant to A.A.C. R14-2-704(A), Commission Utilities Division Staff ("Staff') is required to docket a report ("Staff Report") that contains its analysis and conclusions of the IRPs. In the Staff Report, Staff will assess the compliance of each IRP with the LSE Reporting Requirements contained in A.A.C R14-2-703(C), (D), (E), (F), and (H), and the eleven factors listed under A.A.C. R14-2-704(B). The Staff Report is filed for the Commission's consideration. The IRP Rules require a determination by the Commission whether each IRP filed by the load serving entities complies with the requirements of the IRP Rules. The Commission votes to acknowledge or not acknowledge the plans.

On March 29, 2018, the Commission issued Decision No. 76632 which addressed Commission Staff's assessment of the adequacy of the 2015-2016 IRPs for the aforementioned regulated utilities. In Decision No. 76632, the Commission issued an order that declined to acknowledge the IRPs filed by APS, TEP, and UNS Electric. The Commission adopted a new 3-year timeline for each LSE to follow in preparing and filing the next IRPs.

Commission Decision No. 76632 also states:

> "It is further ordered that for all future IRPs submitted by Arizona Public Service Company, Tucson Electric Power Company, and UNS Electric, Inc., Staff shall, in addition to their existing review requirements and methods, hire one or more third-party analysts to conduct an independent review of the scenarios and portfolios presented in each IRP, and of their respective costs and benefits, and to develop and present alternative scenarios and portfolios the third-party analyst deems are not adequately represented or considered in the IRP. The hiring of a third-party analyst shall require prior Commission approval."

Commission Decision No. 76632

Commission Decision No. 76632

632 specifies additional requirements for each of the Load-Serving Entities' IRPs. The following are relevant ordering paragraphs from the decision:

Table 1: Requirements of Decision 76632

Topic	Requirement
Natural Gas Storage	...Load Serving Entities, except Arizona Electric Power Cooperative, **shall address natural gas storage in greater detail in future IRPs**, including a discussion of efforts to develop natural gas storage, the costs and benefits of natural gas storage, and risks resulting from a lack of market area natural gas storage in Arizona. In addition, natural gas pricing issues are a key driver in future resource planning decisions by Arizona utilities. Thus, a very robust sensitivity analysis, considering a wide variety of natural gas price scenarios, shall be a cornerstone of utility resource planning in Arizona. Consequently, the Load Serving Entities, except Arizona Electric Cooperative, **shall include a wide variety of natural gas price scenarios in future IRPs.**
Storage technologies	IT IS FURTHER ORDERED that all Load Serving Entities, except Arizona Electric Power Cooperative, shall include, in future Integrated Resource Plans, an analysis of a reasonable range of storage technologies and chemistries; and an analysis of anticipated future energy storage cost declines as further discussed in Decision No. 76295.
Storage and non-wires alternatives	IT IS FURTHER ORDERED that all Load Serving Entities, except Arizona Electric Power Cooperative, shall include a storage alternative as a resource option in future Integrated Resource Plans, and shall include an analysis of storage alternatives into their respective processes when considering

	upgrades to transmission or distribution systems, or when considering new build or capacity upgrades for existing generation resources.
Load growth justification report for APS	IT IS FURTHER ORDERED that Arizona Public Service Company shall prepare a report justifying its 2015 and 2016 IRP load growth projections. Said report shall also include an analysis of (A) a "no growth" scenario; and (B) a "low growth" scenario (<1-percent growth) and the resultant implications on APS's resource selections under each scenario. APS shall also include a discussion regarding how each of the required scenarios affect its Three Year Action Plan. Said report shall be filed in the instant docket within 90 days of the Commission's decision in this matter.
No growth and low load growth scenarios	IT IS FURTHER ORDERED that all Load Serving Entities, except Arizona Electric Power Cooperative, shall include "no-growth" and "low-growth (<1%)" scenarios in future Integrated Resource Plans, until further order of the Commission
Thermal as no more than 20% of new resource additions. Tribal Nations	IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson Electric Power Company, and UNS Electric, Inc. in each of their next IRPs shall analyze, along with their preferred portfolio, at **least one portfolio where the addition of fossil fuel resources is no more than twenty percent (20%) of all the resource additions**. In developing each of their portfolios to satisfy this requirement, Arizona Public Service Company, Tucson Electric Power Company, and UNS Electric, Inc. shall each work in good faith with each of the stakeholders [and] to continue to **participate and also work in good faith with any Tribal Nations located in Arizona** that desire to participate in developing the portfolio to satisfy this requirement.
Clean Energy Portfolio Analysis	IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson Electric Power Company, and UNS Electric, Inc., in each of their next IRPs shall analyze, along with their preferred portfolio, at least one portfolio that includes, as a Fifteen year forecast, all of the following: **the lesser of 1000 MW of energy storage capacity or an amount of energy storage capacity equivalent to 20% of system demand, at least 50% of "clean energy resources," which are resources that operate with zero net emissions beyond that of steam, of which 25 MW of nameplate capacity running at no less than 60% capacity factor are renewable biomass resources; and at least 20% of Demand Side Management.**

2 Review of Compliance with Decision 76632

This section provides an independent review of each LSE's IRP with respect to the requirements of 76632.

2.1 APS COMPLIANCE WITH 76632

Natural Gas Storage and Future Natural Gas Price Paths

APS included a short discussion on the prospects of natural gas storage in Arizona. In recent years, Kinder Morgan proposed building a salt dome natural gas storage facility near Eloy, Arizona. The proposed project would store up to 4 billion cubic feet (Bcf) of natural gas. While a storage facility would offer enhanced reliability in the case of a pipeline rupture, the project failed to gain interest from Arizona utilities and is now delayed indefinitely. There are no other natural gas storage projects being considered in Arizona. APS will continue to monitor developments in natural gas storage options.

Given the current situation in Arizona for natural gas storage, APS spent little effort researching how natural gas storage may assist their operations. The situation on the Texas grid in February 2021 highlighted the need for utilities to investigate the interconnected risks of the gas system failing to deliver adequate supply to power plants during periods of extreme weather. While Arizona is unlikely to experience the same cold weather conditions, we recommend APS include in their next IRP an analysis of power system resiliency to extreme weather, including correlated risks to both the power and gas systems. Gas storage could potentially provide a hedge against natural gas supply interruptions and price shocks that would ultimately benefit APS customers.

The second part of the natural gas modeling requirement is to include a wide variety of natural gas price scenarios. APS performed sensitivity analysis on the natural gas price forecast in the production cost model with a low, base, and high natural gas price forecast. The three cases were based on projections from the EIA in the 2020 Annual Energy Outlook. APS found the model outputs were not sensitive to the natural gas price forecast in the model. This is because natural gas generation contributes between 5.5% and 16.7% of the total portfolio energy in 2035, depending on the portfolio. When modeling future states of gas prices, the secular trend (i.e. growth rates) are not as important as understanding power system economics during short periods of scarcity and price spikes, such as what happened to natural gas markets in February 2021 or previous polar vortex events. A simulation-based modeling approach to capture these tail events is recommended.

Finally, policy and economic trends portend a decline in the demand for natural gas. As renewables generate more of the system energy, gas units' capacity factors will decline. At the same time, air source heat pumps are expected to reduce residential and commercial end use of natural gas. The implications of winding down the gas system as well as replacing natural gas with hydrogen and/or renewable natural gas should be studied by APS in the next IRP as part of the broader push for decarbonization.

Storage technologies

Energy storage is considered an essential tool for APS to meet the aggressive renewable energy targets. APS's action plan includes adding 750 MW of energy storage by 2024 and 850 MW by 2025. This amount of battery energy storage was included in all portfolios modeled in the IRP, except for the least-cost baseline. From 2025 to 2035, the three portfolios analyzed by APS ("bridge", "shift", and "accelerate"), add from 4,100 MW to 9,800 MW of battery energy storage. Half of the battery additions are part of solar hybrid installations. All of the batteries have a four-hour duration.

While APS described a wide range of storage technologies other than lithium-ion, such as flow batteries, pumped hydro, CAES, and flywheels none of these were included in the three portfolios. The cost of Li-Ion batteries for 4-hour duration applications has plummeted over the last decade and is expected to fall further. As need for longer duration storage arises in the future (8-hour to 100+ hours), these emerging technologies should be evaluated in more detail.

APS should consider further analysis to determine the most effective schedule for energy storage deployments over a range of scenarios and cost projections. Capacity expansion modeling, resource adequacy analysis, and production cost modeling with sub-hourly dispatch would fully capture the costs and benefits of energy storage technology over time and help APS select the optimal storage deployment pathway.

Storage and non-wires alternatives

APS states on the first page of Chapter 4 that it considers non-wires alternatives to address the challenges associated with changing resource types and high population growth. Aside from this mention, there is no further explicit discussion of non-wires alternatives. It is not clear if non-wires alternatives were considered during the planning process for the 2020 – 2029 transmission plan that APS filed prior to the IRP. Based on the IRP documents, it appears that APS did not give significant consideration for non-wires alternatives like storage and targeted DSM programs. APS has expressed to the Ascend team that storage in the IRP could be installed either as transmission or distribution level assets, both of which would help manage and defer costs associated with additional transmission and distribution level capital spending on traditional utilities investments such as increased capacity, reconductoring, sub-station upgrades, etc.

In future IRPs, APS should include analysis on specific non-wires alternatives considered in the planning process. The analysis should include cost savings associated with non-wires alternatives due to the avoided or postponed transmission costs. APS should evaluate how new non-traditional options such as targeted demand response and storage competes against traditional utility capital investments in transmission and generation.

Load growth justification report for APS

APS provided substantial discussion and analysis supporting the load growth forecast used in the modeling. Itron, a leading load forecasting firm, was retained to review the APS load forecast. The Itron report was included as Appendix E of the IRP document.

Chapter 5 of the IRP describes the APS load forecast, including that their original load forecasting approach was consistent with industry practices while noting that Itron believed that APS should revisit the residential model. APS adjusted the residential model specification consistent with Itron's recommendations. The IRP load forecast describes the expected growth in energy and demand under base, low growth rate, and no growth scenarios. They present energy growth forecasts for residential, C&I, EVs, and data centers. The IRP describes how the average residential usage per customer and the C&I usage per square foot (intensity) for existing customers is forecasted to decline due to the impacts of distributed generation (DG) and demand-side management (DSM), but the sector level usage will grow due to population and business growth. Chapter 5 also describes the past and projected future growth in Arizona's population, forecasting the future growth will not slow as it did following the 2008 recession and it will not accelerate to grow as fast as it did in the 1990s. The chapter describes the increasing interest in DSM and DG and their impact on customer energy usage, their impact on the timing of the system peak and how rooftop solar has only minor impact on the estimated level of the peak. Chapter 5 also describes how growth in data centers and EVs will impact the electric and demand forecasts from 2020 to 2030.

Confidence in APS's forecast of future load growth is strengthened by their process of reaching out to third parties to review and comment on the forecast's models and DSM and DG growth components. APS's response to Itron's suggestions to update their residential forecasts illustrates APS's desire to critically review their approach and make the necessary updates. The ongoing development of tools designed to forecast future DSM and electric vehicles (EV) growth also indicates the importance of these transformative technologies in future load growth.

Ongoing updates to the forecasts of DSM, DG, distributed storage, and EV will be necessary to maintain a firm understanding of how these technologies are impacting future energy and demand growth. Growth in these technologies, and how the technologies are used (timing of EV charging and charge and discharge of distributed storage), can have large impacts on energy and demand growth.

Pulling the forecast of data center growth out from the general C&I load forecast helps to improve the general understanding of the C&I and the data center forecast. This approach should be maintained.

Itron's review of APS's load forecast stated that the forecasts assume that DSM and DG do not decay. APS's DSM programs incorporate behavioral programs with very short persistence and existing distributed solar production decays at a rate of 1% to 1.5% per year. If behavioral DSM and DG maintain their importance within the APS load forecast, careful review of the no decay assumption is warranted.

No growth and low load growth scenarios

As directed, APS performed sensitivity analysis on the portfolios to include a no growth and a low growth of 0.9% annually for customer load. The base case load growth was estimated to be 2.1% annually. The results are summarized in Table 7-11 on page 154 of their IRP. The range of load growth modeled (0 to 2.1% annual growth) has a significant effect on the revenue requirement (11% difference), the capital expenditures (88% difference), the share of clean energy serving load (7% difference), and the amount of renewable curtailment (45% difference). Other variables shown have relatively small changes in output values for the range of load growth scenarios.

APS followed the directive in performing the load growth sensitivity analysis. There was no consideration for a high load growth future. This may have been a result of assuming a 2.1% growth in the base case which is high compared to most places in the country.

Future IRPs should evaluate an "electrify everything" pathway, which would imagine a near total transition to electrified transportation and building sector. Load growth could also be higher than expected due to climate driven increases in average temperature and more frequent extreme heat waves.

Thermal as no more than 20% of new resource additions. Tribal Nations

The three portfolios assembled for the IRP analysis limit thermal to less than 20% of new resource additions. The "Bridge" portfolio has an added natural gas capacity slightly less than 20%, "Shift" has more aggressive reductions, and "Accelerate" has zero added thermal capacity. The natural gas capacity included in the modeling is assumed to be able to be converted to hydrogen at a future date. Additionally, all portfolios include retiring the 1,357 MW of coal from Four Corners and Cholla.

The coal retirements have an important consequence for the Tribal communities. Equity issues were not specifically discussed in the IRP document, but APS attempts to address equity issues for communities affected by the retirements with enhanced DSM offerings. The excerpt below was taken from a data response from APS explaining their initiative to address equity.

"APS recognizes the important role coal plants play in the local communities and has addressed equity issues in its current rate case (Docket E-01345A-19-0236). Please see the rebuttal and rejoinder testimonies on Coal Community Transition (CCT) of APS witness Barbara Lockwood for details.

APS addressed equity issues extensively with the DSM planning process. Equity is a strong consideration in DSM including special program offerings and set asides for renters, limited income, schools, non-profits, and small businesses. In addition, APS also launched a new Tribal Communities Energy Efficiency program that is targeted to provide energy efficiency rebates and services exclusively to Hopi and Navajo tribal communities in Northern Arizona impacted by coal plant closures. This program was initiated by the Commission in recognition of important equity considerations associated with the impacts of coal plant closures in these communities. "

In future IRPs, APS should provide more analysis showing how much natural gas/hydrogen capacity is needed to maintain reliability. Detailed reliability analysis should provide more insight into the portfolio need for flexible capacity to manage the high level of renewables. Additionally, APS should provide an economic assessment of converting natural gas to hydrogen or other green fuels such as ammonia or renewable natural gas. The current IRP could have been improved with a more robust analysis of hydrogen conversions.

Future planning processes should also build upon and expand stakeholder engagement activities, including meaningful input and consideration of equity issues, and IRPs should continue to document these efforts and the stakeholder engagement and feedback.

Clean energy portfolio analysis

All three of the portfolios exceed the 50% clean energy goal by 2035. The energy mix in 2035 ranges from 79% clean energy to 91% clean energy. The largest contributions come from renewables (mainly solar) and nuclear. The "Accelerate" portfolio covers the requirement of 25 MW of biomass. APS is planning to install 850 MW of battery storage (four-hour duration) by 2025. APS shows that they meet the clean energy portfolio requirement of Decision 76632.

The portfolios analyzed in the IRP were designed by hand. Ascend recommends APS incorporate both capacity expansion modeling and hand designed portfolios to meet various clean energy targets. This would allow APS to optimize resource costs for various clean energy targets.

2.2 TEP COMPLIANCE WITH 76632

Natural Gas Storage

TEP discusses natural gas storage in Chapter 8 of its IRP. The discussion points out that there are no natural gas storage facilities in the state of Arizona and that an investment in natural gas storage would require joint participation with other utilities and depend on both gas storage economics and the degree to which natural gas is being used as a fuel in TEP's portfolio. Additionally, the IRP includes a spread of portfolio costs that reflect a variety of gas future conditions and stochastic gas price simulations, shown in charts 32, 35 and 36. A high degree of correlation between gas and power prices were held, but these did not include associated correlations with load or renewable generation.

The TEP IRP argues that the case for gas storage should be dependent on a coordinated regional effort. However, the discussion of comparative economics with other storage technologies should be clarified, given that energy storage options vary greatly in their durations, and by extension, in the reliability challenges that they address.

Overall, the discussion of gas storage is brief and does not provide a detailed analysis of the arguments for or against developing natural gas storage in Arizona. Future IRPs should provide additional in-depth analysis related to system reliability and the risks/consequences of pipeline distribution.

Storage technologies

TEP discusses storage technologies in Chapter 10 of its IRP. The IRP highlights that the vast majority of battery systems are lithium-ion, identifies the lack of technology diversity in storage as a potential risk, and states that TEP will continue to explore newer storage technologies as options emerge. Storage cost forecasts are discussed in Chapter 7, with TEP using the NREL ATB 2019 storage cost followed by relative cost declines from Wood Mackenzie. This forecast results in a decline in nominal capital costs of nearly 40% by 2035. The comparison between storage durations is mainly done on a levelized cost of energy basis which is not an appropriate metric for comparing the cost of energy storage.

The TEP IRP considers future cost declines of storage that are consistent with common forecast sources but does not provide sufficient consideration to alternate storage technologies. This is particularly important given the different cost versus power tradeoffs of different storage technologies, and the corresponding services that they are suited for providing the grid. In addition to lithium ion, storage options that should be considered are flow batteries, liquid air, metal air, hydrogen/renewable fuels, and other emerging technologies.

Overall, the discussion of storage technologies is very brief. Future IRPs should provide a more detailed discussion of the options and applications of storage at different durations, as well as evolution in effective load carrying capabilities as storage penetration increases.

Storage and non-wires alternatives

Each of the TEP IRP portfolios includes significant additions of storage resources. Chapter 4 discusses holistically the future of the distribution grid, and the roles of energy efficiency, demand response, storage, and microgrids. While storage is not specifically discussed as a non-wires alternative, the IRP demonstrates that TEP is paying attention to the evolving nature of the distribution system and is aware of the potential role of storage as a distribution-level resource.

Historically, issues surrounding the distribution grid were not addressed in power supply resource planning. Storage is relatively a new technology that has co-benefits between energy supply and the distribution grid including serving system peak demand and providing various services to the distribution grid such as voltage support, resilience benefits, and traditional infrastructure spending deferral. Future IRPs should continue to discuss the evolution of the distribution grid and include behind-the-meter and distribution-level storage as part of the solution options. NWAs will become more valuable with the consistent increases in peak demand and the limitation of expanding existing transmissions and distribution networks.

No growth and low load growth scenarios

TEP's load growth scenarios are described in Chapter 8 of the IRP, and include base (L1), no growth (L2), low growth (L3), and low and high EV sales (L5 and L6 respectively) load scenarios. The portfolio analyses described in chapter 9 uses the base load forecast, with additional scenarios low and high load scenarios presented in appendix

D. TEP presents additional load growth scenarios for the preferred portfolio in Chapter 10. This discussion includes alternations to the reference portfolio for each of the load forecasts that maintain the same reserves and renewable energy penetration as the base load (L1) scenario.

Thermal as no more than 20% of new resource additions. Tribal Nations

None of the 15 portfolios presented in the TEP IRP include any new thermal resource additions, and thus suggested portfolios all comply with the 20% requirement.

The IRP does not discuss any engagement specifically with tribal nations, though TEP mentions stakeholder workshops in May 2019 and March 2020 and makes frequent reference to stakeholder support and working with stakeholders in designing the portfolios used in the IRP.

Future planning processes should also build upon and expand stakeholder engagement activities, including meaningful input and consideration of equity issues, and IRPs should continue to document these efforts and the stakeholder input and feedback.

Clean energy portfolio analysis

Portfolio P05 meets the requirements of Decision 76632. Many other portfolios, including TEP's preferred portfolio, meet the requirements of the Clean Energy Portfolio apart from the inclusion of 25 MW of biomass. Future IRPs would benefit the use of a capacity expansion model to optimize clean energy targets.

2.3 UNSE COMPLIANCE WITH 76632

Natural Gas Storage

UNSE discusses natural gas storage in Chapter 8 of its IRP. The discussion mirrors the TEP IRP, identifying that there are no natural gas storage facilities in the state of Arizona and that an investment in natural gas storage would require joint participation with other utilities and depend on both gas storage economics and the degree to which natural gas is being used as a fuel in UNSE's portfolio. Additionally, the portfolio cost analysis includes a spread that reflect a variety of gas future conditions and stochastic gas price simulations, shown in Charts 18 and 20. Correlations of 90% between gas and power prices were held, but these did not include associated correlations with load or renewable generation.

Like TEP, the discussion of gas storage is brief and does not provide a detailed analysis of the arguments for or against developing natural gas storage in Arizona. Future IRPs should provide additional discussion and analysis related to system reliability and the risks/consequences of pipeline distribution.

Storage technologies

UNSE discusses storage technologies in Chapter 9 of its IRP. The IRP highlights that the vast majority of battery systems are lithium-ion, identifies the lack of technology diversity in storage as a potential risk, and states that UNSE will continue to explore newer storage technologies as options emerge. Storage cost forecasts are discussed in Chapter 7, with UNSE using the NREL ATB 2019 storage cost followed by relative cost declines from Wood Mackenzie. This forecast results in a decline in nominal capital costs of nearly 40% by 2035.

The UNSE IRP considers future cost declines of storage that are consistent with common forecast sources but does not provide sufficient consideration to alternate storage technologies. This is particularly important given the different cost versus power tradeoffs of different storage technologies, and the corresponding services that they are suited for providing the grid. In addition to lithium ion, storage options that should be considered flow batteries, liquid air, metal air, hydrogen/renewable fuels, and other emerging technologies.

Overall, the discussion of storage technologies is very brief. Future IRPs should provide a more detailed discussion of the options and applications of storage at different durations, as well as evolution in effective load carrying capability as storage penetration increases.

Storage and non-wires alternatives

Each of the UNSE IRP portfolios includes significant additions of storage resources. Chapter 4 discusses holistically the future of the distribution grid, and the roles of energy efficiency, demand response, storage, and microgrids. While storage is not specifically discussed as a non-wires alternative, the IRP demonstrates that UNSE is paying attention to the evolving nature of the distribution system and is aware of the potential role of storage as a distribution-level resource.

Future IRPs should continue to discuss the evolution of the distribution grid and include behind-the-meter and distribution-level storage as part of the solution options. NWAs will become more valuable with the consistent increases in peak demand and the limitation of expanding existing transmissions and distribution networks.

No growth and low load growth scenarios

UNSE's load growth scenarios are described in Chapter 8 of the IRP, and include base (L1), low growth (L2), no growth (L3), and high growth (L4) load scenarios. The portfolios analyses described in Chapter 9 of the IRP are all for the base load forecast, while sensitivities to the different load growth scenarios are described in Chapter 10. This discussion includes alternations to the reference portfolio for each of the load forecasts that maintain the same reserves and renewable energy penetration as the base load (L1) scenario.

Because UNSE plans to procure resources through all source RFPs and has minimal major capital expenditures into large thermal assets, it has relatively high flexibility in adjusting procurement according to the realized changes in load. As a result, UNSE is largely insensitive to load uncertainty. However, the IRP does not present analysis of the additional costs or savings that would be incurred as a result of procuring for one load future only to have a different one arises. This could be done, for example, by aligning to one load forecast for the beginning of the period, followed by a transition to the other load forecast, and comparing cost differences between portfolios that are developed for one load forecast or the other.

Future IRPs should provide greater discussion of the risks of market dependence, over-procurement, and the portfolio cost sensitivity to inaccurate load forecasts.

Thermal as no more than 20% of new resource additions. Tribal Nations

The portfolios evaluated by UNSE are listed in Chapter 9, Table 18, in its IRP. Portfolios P01a, P02a, P02c, and P03a all have thermals as no more than 20% of the resource additions. Portfolio P02b, the preferred (reference) portfolio, should likely also fit this definition, depending on how energy efficiency is counted as a resource addition, given that P02b has a greater amount of energy efficiency than P02a.

The IRP does not discuss any engagement specifically with tribal nations, though UNSE mentions stakeholder workshops in December 2019 and makes frequent reference to stakeholder support and working with stakeholders in designing all source RFPs for future resource procurement.

Future planning processes should also build upon and expand stakeholder engagement activities, including meaningful input and consideration of equity issues, and IRPs should continue to document these efforts and the stakeholder input and feedback.

Clean Energy Portfolio Analysis

UNSE complies with the Clean Energy Portfolio requirement of Decision 76632. The portfolios considered are listed in Table 18 in Chapter 9 of the IRP. Portfolio P01a is stated as meeting the requirements of this order, with 25MW of Biomass, 100MW of storage, and 20% of demand-side management (22% energy efficiency). Additionally, UNSE's preferred portfolio mostly meets this requirement, with the exception of the biomass resources. Future IRPs would benefit the use of a capacity expansion model to optimize clean energy targets.

3 Review of Integrated Resource Plans

The following chapter provides a critical review of the Integrated Resource Plans filed with the ACC in Summer 2020. Section 3.1 discusses the Ascend team's view of how resource planning is changing given the evolution in energy technologies, increases in renewables across the Western grid, and changing expectations of stakeholders. Section 3.2 describes Ascend's approach to this review. Section 3.3 presents the results of Ascend's review for each LSE.

3.1 MODERN RESOURCE PLANNING: A PRIMER

Integrated resources planning is evolving rapidly alongside the seismic shifts in the energy landscape. In the past, planning analysts would develop load forecasts and predict how many baseload (coal, nuclear), mid-merit (natural gas combined cycles) or peakers (natural gas turbines) would be needed. The instructions were simple: maintain system peak reliability while minimizing costs to the ratepayer. Today's planner must balance many more priorities, including balancing and optimizing across the following new principals of resource planning:

- **Maintaining system reliability** – the core foundational mission remains the same: keep the lights on (most) of the time. No power system is built to be reliable 100% of the time, but the "1 day (24 hours) of outage every ten years (87,600 hours) remains the industry standard for peak reliability. However, now the power system must also retain enough flexible capacity to be able to integrate intermittent renewable energy as well as ramp up to meet the evening peak when the sun goes down. Planners must also understand how the future grid can maintain reliability relying on duration limited resources such as battery storage, which today generally discharges for only four hours. Add on top of that the need to plan for more extreme weather like heat waves driven by climate change, which can cause more resource outages, spike up demand, and threaten transmission lines. In short, maintaining reliability is becoming an increasingly difficult challenge.
- **Reducing greenhouse gas emissions to zero by mid-century** – Climate scientists from the Intergovernmental Panel on Climate Change (IPCC) to the National Academy of Sciences and many others have made clear that human civilization must rapidly reduce emissions that cause anthropogenic climate change. To avert the worst consequences, emissions need to drop to zero by mid-century. The electricity sector plays a key role in this transformation, as zero carbon energy technologies such as nuclear, renewables, storage, and clean fuels can be used to power buildings, transportation, and much of industry. Across the country whether driven by state mandates or customer pressure, utilities are strategizing and preparing for a wholesale transition to clean energy.
- **Equity and Environmental Justice** – Planners must understand and incorporate increased stakeholder and societal focus on the negative impacts of fossil fuel environmental pollution disproportionately impacting poor communities and communities of color. At the same time fossil power plant closure has major impacts on the communities in which they provided good paying jobs and tax revenues. A transition to clean energy must provide impacted communities with opportunities to take part in the clean energy economy. Equity and justice in resource planning is a relatively new area of concern but one that is important to address head on and bring in voices that have been historically marginalized in the past.
- **Keeping rates affordable** – Electricity remains a foundational piece of modern human livelihood and utilities must achieve the first three goals while also keeping the cost of electricity affordable for all. If full decarbonization requires a transition of space heating and transportation to electricity,

affordability must be maintained. On the one hand, recent and ongoing advances in technology have made energy efficiency, demand response, renewables, and storage competitive with traditional fossil fuel resources. On the other hand, additional spending on transmission and distribution is likely to be required to support the renewable and more-distributed future grid.

With an increasingly complex task at hand, resource planners must rely on more advanced analytical tools and techniques. Modern planning tools leverage the advances in computing technology to drill down in finer and finer detail. Planners use "production cost models" or PCMs, which simulate power system operations and calculate the cost to serve load within the broader energy market and a utility's portfolio of generation and demand-side resources. These models are becoming increasingly sophisticated and require finer details, including using Monte Carlo simulation techniques and simulating dispatch down to 5-minute levels. We call these models "high-definition" or HD PCMs. Higher definition leads to deeper insights and more informed decisions. The regulatory standards of prudency state that planners must use all information known and knowable and achieve this standard by using the best HD PCMs available. Here are some key features of HD PCMs and why they should be used over traditional PCMs:

- **HD PCMs include weather as a fundamental driver of power system conditions**. Traditional PCMs operate under the foundational assumption that power price is approximated by fuel cost multiplied by the heat rate of the marginal unit to serve load. Much of the system energy in the future will be supplied by renewables with no fuel cost but seasonal and intermittent output. If weather is becoming the new fuel, planning models must include weather as a fundamental driver of power system conditions. Weather should be modeled as it actually behaves rather than simply using typical weather year or average shapes. Simulating weather conditions as it drives load and renewable output is the most robust approach.
- **HD PCMs capture risk and uncertainty.** Deterministic production cost modeling provides a single lens of the future by using hourly weather-normalized load, average wind and solar production, and market price fluctuations that have significantly less variability than actual observations. In the past, computing limitations made stochastic modeling impractical. Deterministic models were initially developed when computing power was significantly more costly and less available, but new systems have enabled more sophisticated modeling tools. Although the hourly deterministic production cost modeling adequately informed regulatory and merchant decisions over the last three decades, today, the limitations of this approach are increasingly exposed by high renewable penetration rates and the impact of weather (a fundamentally stochastic phenomena) becoming a major fuel source. HD PCMs use stochastic approaches to characterizing the uncertainty in weather, load, renewable production, power prices, gas prices, and forced outages. Capturing a properly correlated distribution of production cost outcomes helps drive planning towards a more robust risk-informed decision-making framework.
- **HD PCMs can simulate down to the 5-minute level -** When resource planning models moved from load duration curves to hourly chronological dispatch it represented a significant improvement. With the increase in renewable generation, models now need to step into the intra-hour or sub-hourly time dimension. Models that use hourly time steps gloss over the variable operations of flexible resources due to quick changes in renewable output in the intra-hour period. The value of a resource's ability to respond to real-time 15- and 5-minute prices (or perform sub-hourly renewable integration services) with quick start-up and ramping to full load with little to no start-up costs, is missed when only modeling at the hourly level.

3.2 REVIEW METHODOLOGY

The Ascend team reviewed the following key requirements for a modern IRP:

Stakeholder Process

The decisions utilities make have far reaching implications for stakeholders, including different classes of rate payers, power plant workers, environmental groups, shareholders, disadvantaged communities, and many others. Ascend reviewed each LSE's stakeholder process, including engagement with Tribal communities, to determine if stakeholder engagement was thorough, accessible, and meaningfully contributed to the final IRP.

Getting Inputs and Assumptions Right

The old saying, "garbage in = garbage out" is eternal. Getting the right results requires a thorough and thoughtful approach to investigating the state of the market and energy technologies that will be used as input assumptions. This is especially critical today when the costs of renewables and storage are declining so quickly.

- Does the long-term price forecast capture the changing dynamics of high-renewables systems? These include declining implied heat rates, changing power price shapes, and increasing price volatility. How were the price curves developed? What assumptions are behind those curves? Is it consistent with current and expected policy and economics?
- What are the cost curves associated with each power resource technology? Are they consistent with today's quoted prices and current cost curves from reputable sources such as NREL, Lazard, BNEF, etc.?
- What is assumed about the cost of carbon, either as a carbon tax, cap-and-trade, or social cost of carbon?
- How is load modeled? Are new types of loads such as electric vehicles included? How are load reducing technologies such as behind-the-meter solar and demand response captured? Are the distributed energy resource (DER) assumptions reasonable?

Avoiding Model Limited Choice

Model limited choice is when limitations in the modeling tools lead to poor decisions. For example, using weather normalized deterministic inputs rather than a simulation approach with weather as a fundamental driver, which results in undervaluation of flexible resources. Capturing volatility is critically important when renewables take up more share of the supply stack. Another example is failing to add the sub-hourly value of flexible resources. For example, today up to 70% of the value of storage is found in the intra-hour operation providing regulation and real-time market energy. An hourly only approach fundamentally undervalues storage relative to traditional resources. Additional things we look for include:

- How is reliability planning conducted? Is there loss of load probability analysis? What is the expected capacity contribution of renewables? Is there any planning for extreme events such as the summer 2020 western heat wave?
- How are ancillary services modeled? Do the IRPs take into account the increased need for A/S as a function of renewable energy penetration?
- How is integration with the Western EIM captured?
- How is cost calculated? How is NPV calculated? Is risk monetized and included in decision analysis?
- How is the model validated?

Developing a diverse set of Scenarios and Portfolios

A comprehensive approach to developing scenarios and portfolios is a best practice with respect to managing uncertainty about future conditions. Ascend leveraged its experience working across the country in resource planning to identify if there are any alternative scenarios and portfolios that would provide insight and benefit to the IRPs. In particular, the Ascend team reviewed:

- Are all potential policy pathways captured? This may include a national clean energy standard, carbon tax, state level renewable requirements, a Western RTO, etc.
- Are there scenarios around commodity prices (e.g. gas and power prices), and why?
- Does the LSE use a capacity expansion algorithm, or develop discrete portfolios? Are there sensitivity runs done and why? What was the process for developing discrete portfolios?

3.3 REVIEW OF APS IRP

3.3.1 IRP PROCESS

In developing the IRP, APS laid out several planning principles. First, APS notes that in January 2020 the company announced its goal to gradually transition to 100% clean energy by 2050. Interim goals along the path to 100% include achieving 65% clean energy by 2030 and eliminating coal by 2031. To achieve these goals, APS will rely on clean generation from Palo Verde nuclear power plant, increased energy efficiency savings, and significant deployment of renewable generation and battery storage.

APS started the IRP process in late 2018 with a group of stakeholders representing a wide range of utility industry experts from resource developers, environmental advocacy groups, and power companies. Some of the groups who submitted comments include the Sierra Club, Black Mesa Trust, Vote Solar, Southwest Energy Efficiency Project, Arizona State University, Calpine Energy Solutions, Western Resources Advocates, and Arizona Electric Power Cooperative. They conducted seven day-long meetings over a nine-month period. The meetings allowed the stakeholders to closely examine, question and provide feedback on the IRP assumptions and methods. Stakeholders proposed a wide range of portfolios to include in the IRP. The consulting firm Energy and Environmental Economics, Inc. (E3) conducted a high-level economic analysis with the stakeholder group. Ultimately, the efforts by the group led to the three portfolios included in the APS IRP analysis. Appendix F starting on page 540 of the IRP included a presentation from E3 regarding the stakeholder process.

E3 laid out three goals for the stakeholder process. First, they created a tool in Excel that allowed stakeholders to perform high level modeling on the proposed portfolios. The tool was meant to balance modeling complexities and time limitations while giving stakeholders results that are directionally consistent with industry standards. Stakeholders were able to test assumptions on technology cost, load growth, and other key variables. Second, E3 aimed to provide stakeholders with a more active means to participate in the portfolio planning process. Third, Stakeholders were able to put forth scenarios to study and inform APS's development of the IRP.

The main takeaways from the stakeholder process, as reported by E3, were

1. Continued population growth will drive significant investment in APS's system
2. Significant new clean resources will be needed to achieve carbon reduction goals

3. Broadly defined policies to encourage clean energy and carbon reductions provide more affordable and flexible options than prescriptive goals
4. Palo Verde is critical to meeting future clean energy goals at low cost
5. Early retirement of coal will have significant carbon benefits, but would require large replacement investments
6. Even with deep decarbonization, firm gas resources will be crucial for reliability while running infrequently

On page 26, APS dedicates several paragraphs to the collaborative stakeholder process in developing plans to transition to a clean energy future. The stakeholder process is key to charting a path to a carbon-free grid at a reasonable cost and meeting customers' changing energy needs.

APS did not include discussion in the IRP document regarding consultations with affected communities from coal retirements other than a small section on page 26 stating that APS is committed to working with its employees and stakeholders on the economic impact and other effects of retiring coal assets. In response to a data request, APS stated that they are planning to enhance energy efficiency offerings to the affected communities. Representatives from the Navajo and Hopi tribes submitted comments in the IRP docket arguing that APS has not made any indication of plans to work with tribal leaders in the development of renewable energy projects to replace the retiring coal. They feel strongly that APS has benefitted greatly from tribal coal while the tribal communities have endured negative environmental and health impacts from the coal power plants. To right the past wrongs, the tribal representatives argue that APS should commit to developing future renewable projects in collaboration with the tribal communities. They also argue that APS should retire all coal sooner than 2031.

The Sierra Club and Southwest Energy Efficiency Project provided comments that include independent analysis of the IRP portfolios. They claimed that the process of fulfilling data requests to build the independent analysis took a few weeks. The number of weeks and submitted requests were not specified.

3.3.2 INPUTS AND ASSUMPTIONS

Demand Side

For the IRP review, the inputs and assumptions to the forecast of annual energy and peak demand from 2020 to 2035 were disaggregated into five components. The first component is the "base" energy or peak demand, which represents the natural evolution of load driven by population and economic growth before accounting for the impacts of programs and new technologies. The remaining four components are:

- **Electrification:** The increase in energy and demand associated with electric vehicle adoption and the conversion of end uses to electricity.
- **Energy Efficiency**: The decrease in energy and demand associated with improvements in energy efficiency as a result of utility programs.
- **Distributed Generation**: The decrease in energy and demand associated with behind-the-meter generation, primarily photovoltaics.
- **Demand Response**: The decrease in demand associated with utility demand response programs.

The APS IRP data generally included the necessary data series for the 2020 – 2035 period of the IRP. APS's 2020 IRP provided a variety of data sources that were used to develop the forecast, including:

- APS 2020 DSM Opportunity Study
- APS Time Series Hourly Load Forecast
- Itron's review of APS's Load Forecast
- APS Coincident Peak Demand Disaggregated by DSM and by Month and Customer Class
- APS Energy Consumption by Month and Customer Class
- APS Forecast of EV Sales and Energy Consumption
- APS Forecast Documentation
- APS Staff Responses to Data Requests

The base energy forecast for APS increases from 28,905 GWh in 2020 to 47,448 GWh in 2035. The annual growth rate between 2020 and 2021 is approximately 4.1%, falling to 2.5% between 2034 and 2035. The annual growth rate in the APS baseload forecast is 2.5% between 2034 and 2035. The base forecast for peak demand shows growth from 7,470 MW in 2020 to 11,271 MW in 2035. The annual peak demand growth rate in 2020 is 2.41% substantially lower than the energy forecast. The annual peak demand growth rate between 2034 and 2035 is 2.37%, very similar to the 2020 peak demand growth rate and the energy growth rate during this period. Given assumed growth in customers, we feel these are reasonable growth rates for energy. We also find that lower relative demand growth is a reasonable expectation as peak demand becomes muted by adoption of load modifying technologies like behind-the-meter solar and storage, controllable loads, and smart EV charging.

The electrification data provided by APS included base, transformative, and blended EV adoption scenarios. The APS EV forecast for 2019 estimated annual usage at 40 GWh growing to 56 GWh in 2020. The APS EV usage is forecasted through 2038, where annual usage is expected to be 1,714 GWh, roughly 300,000 EVs. The growth rate in electrification energy use exceeded 100% during the early 2020s, declining to under 20% by 2035.

In addition to the IRP, Verdant reviewed the APS 2021 DSM plan, which has a target of approximately 335,000 MWh of annual energy savings from efficiency measures while the APS Energy Consumption by Month and Customer Class listed an incremental 2021 energy efficiency program saving of approximately 175,000 MWh. The targeted energy savings in the 2021 DSM plan, closely approximate the energy efficiency savings necessary to meet the proposed Energy Rules targets.

Supply Side

Existing Resources

APS provided a review of the existing supply side resources along with potential candidate resources. The existing resources include:

- Palo Verde, a large nuclear power plant near Phoenix, of which APS is the majority owner with 1,146 MW. APS assumed that Palo Verde will be part of the portfolio through 2035.
- The Four Corners and Cholla coal-fired power plants, with 1,357 MW of combined capacity. Given APS's stated plans to transition to a clean energy system, they will retire all coal power by 2031 with Cholla going offline in 2025 and Four Corners in 2031. No early retirement scenarios for coal were considered in the IRP.
- Natural gas generation comprises the largest share of existing resources in the APS portfolio. There are eight natural gas generation stations owned by APS for a total nameplate capacity of 3,573 MW plus an additional 1,660 MW of purchased power from natural gas resources. Five of the plants have units that are over fifty years old, meaning that a portion of the existing natural gas capacity is likely

to retire over the next 15 years. APS views natural gas as a resource that allows greater integration of renewables due to the flexibility of gas-powered assets. The lower carbon emissions, compared to coal, also make natural gas a bridge resource enabling the transition to a carbon-free future. Over time, APS acknowledged that natural gas plants must also transition to a low/no-carbon resource, potentially by converting to hydrogen/renewable fuel or employing carbon capture technology.

- Renewables make up 883 MW of APS resources with solar providing 567 MW. This does not include customer-owned solar, which is currently at 1,044 MW. Wind comprises 289 MW from three locations with two of the locations in neighboring New Mexico.

APS also controls two microgrids totaling 32 MW in capacity. One of the microgrids serves a Marine base in Yuma and the other serves the Aligned Data Center near Phoenix. Both grids act as redundant sources of power for the customers in the event of an outage.

Future Resources

APS considered a wide variety of new resources for use in the portfolios. In the report they list thermal (natural gas turbines and combined cycle plans), nuclear (advanced reactor technology and small modular reactors), renewable (wind, solar, geothermal and biomass), and storage options that were considered. The storage options covered Li-Ion batteries, flow batteries, compressed air energy storage, and pumped hydro storage. A footnote states that all storage technology options assumed four hours of duration, which is inconsistent with industry standards for compressed air energy storage (CAES) or pumped hydro storage. Generally, resource planning assumes CAES and pumped hydro will provide long-duration storage of at least 8 hours, usually up to 12 hours.

Technology Costs

Table 2-3 in the IRP document lists assumed costs for potential future resources in dollars per installed kilowatt for the year 2022. APS provided future cost curves for all potential resources as part of a data request. ***(Begin confidential information)*** *[Redacted due to confidentiality]* ***(End confidential information)***. The exceptions are for solar PV, batteries (lithium-ion and flow), and wind. Solar PV and batteries are assumed to get cheaper over the time horizon of the IRP, while wind costs are expected to increase, although at a slower rate than thermal assets.

Technology cost assumptions for renewables and batteries used in this IRP are in line with other reputable resources. Projections used in the APS IRP are shown in the following graphs with comparable cost curves from Ascend for storage and the National Renewable Energy Laboratory (NREL) for solar and wind. The cost projection used by APS for energy storage, utility scale solar, and wind are lower in all graphs.

(Begin confidential information)

[Redacted due to confidentiality]

Figure 1: Capital cost comparison (li-ion 4-hour battery)

[Redacted due to confidentiality]

Figure 2: Capital cost comparison (utility scale solar PV)

[Redacted due to confidentiality]

Figure 3: Capital cost comparison (onshore wind)

(End confidential information)

Market Assumptions

APS engaged E3 to develop power price forecasts at the Palo Verde trading hub. ***(Begin confidential information)*** *[Redacted due to confidentiality].* ***(End confidential information)*** By 2035, excess solar during on-peak hours is expected to drive prices down well below the off-peak hours. ***(Begin confidential information)*** *[Redacted due to confidentiality]* ***(End confidential information)***. The APS price forecast created by E3 closely matches Ascends price forecast on an annual basis by the year 2030. In the early years, Ascend's price forecast is much higher because it is anchored to power prices in the futures' market for power traded at Palo Verde. While the two forecasts converge on an annual level, the Ascend forecast keeps on-peak prices higher than off-peak prices during the middle of summer, shoulder months have higher off-peak prices than on-peak prices.

(Begin confidential information)

[Redacted due to confidentiality]

Figure 4: Palo Verde annual power price comparison

[Redacted due to confidentiality]

Figure 5: Palo Verde monthly power price comparison

(End confidential information)

Natural gas prices are shown in the model as rising very slightly over the study period. From 2021 to 2035, APS estimates natural gas to rise from $2.25 per MMBTU to about $2.80 per MMBTU. APS derived the forward curve for natural gas prices from an analysis of market forward prices. Ascend used a similar method to derive natural gas prices and produced a forecast that is slightly lower than the APS forecast.

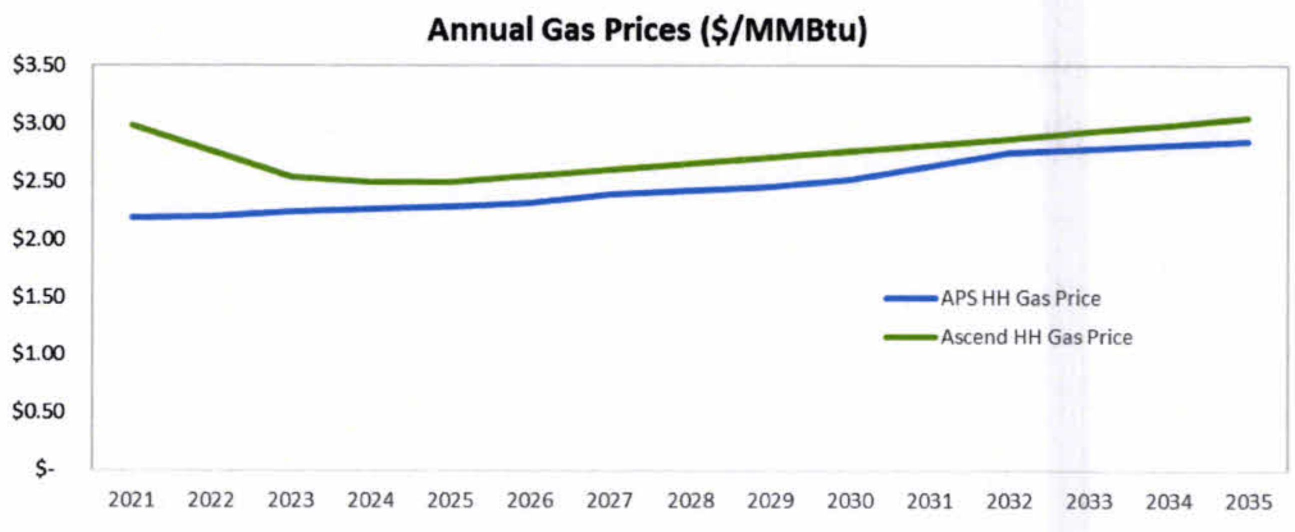


Figure 6: Henry Hub annual gas price comparison

(Begin confidential information)

[Redacted due to confidentiality]

Figure 7: Henry Hub monthly gas price comparison

(End confidential information).

Implied heat rates function like a normalized power price that accounts for the impact of gas prices and are an indicator of whether gas generation resources can operate profitably in the market. On average, Ascend and APS's implied heat rates are fairly aligned. The difference in the first years is a result of having higher gas prices in the Ascend assumption due to alignment to market forwards. ***(Begin confidential information)*** *[Redacted due to confidentiality]* ***(End confidential information)***. APS spring and summer heat rates are relatively low leading to depressed valuation for gas resources.

(Begin confidential information)

[Redacted due to confidentiality]

Figure 8: Annual implied heat rates, calculated as power price in Palo Verde divided by gas price in Henry Hub

[Redacted due to confidentiality]

Figure 9: Monthly implied heat rates, calculated as power price in Palo Verde divided by gas price in Henry Hub

[Redacted due to confidentiality] ***(End confidential information)***. APS used the currently traded prices as the baseline for carbon price modeling. Overall, APS' forecast is fairly aligned with Ascend's but is however likely to underestimate the cost of market purchases and the value of market sales, which could lead to an undervaluation of portfolio resources.

Modeling Approach

Demand Side

In Verdant's opinion, APS's IRP demand forecast was developed using industry best practices. They hired third-party consultants to assist in the development of forecasts of DSM opportunities or DSM potential and EV Sales and Energy Consumption. They hired Itron, a leading load forecasting firm, to review the APS load forecast, and APS responded to this review by adopting one of Itron's suggested methods to improve the residential load forecast. APS's growth in their load forecast is largely due to forecasts of growth in Arizona's population, business growth and growth in data centers. Given previous growth in Arizona's population, the forecasts of these underlying input to energy consumption appear within the likely bounds.

APS's DSM potential forecast appears thorough. The DSM forecast provided by APS is slightly higher than the DSM forecast in the IRP. Forecasting EV purchases and energy usage is a highly uncertain activity given the nascent nature of this market, but APS's use of a forecast developed by Guidehouse, a well-respected market research firm, highlights APS's effort to develop tools and establish an initial forecast of energy usage for this technology.

Supply Side

In previous IRPs, APS used capacity expansion modeling to determine a least-cost portfolio that meets future load growth. But for this plan, APS wanted to develop a range of portfolios representing a measured pace of renewable and storage implementation on one end (Bridge Portfolio) to meet their Clean Energy Commitment, a very aggressive pace of renewable and storage implementation (Accelerate Portfolio) on the other end, and one in between (Shift Portfolio). In previous IRP's, APS used capacity expansion models to create portfolios, which is standard in resource planning. In the 2020 IRP, APS stated that they "wanted to develop a range of portfolios representing a measured pace of renewable and storage implementation on one end (Bridge Portfolio) to meet our Clean Energy Commitment, a very aggressive pace of renewable and storage implementation (Accelerate Portfolio) on the other end, and one in between (Shift Portfolio)." For the 2020 approach, APS stated "the capacity expansion model would not correctly model the more diverse resources." This is a critical flaw in the APS modeling software. High levels of renewable resources in a model add complexity but should not be a barrier to implementing a capacity expansion model. APS would have been better off running capacity expansion models with varying limits set for carbon emissions. APS ended up using a capacity expansion model to construct a least-cost "technology agnostic" portfolio to be used as a benchmark for the analysis of the other portfolios.

The **Bridge portfolio** added solar, wind, lithium-ion batteries (four-hour duration), and natural gas combustion turbines to meet future capacity and energy needs. These resources were selected to achieve stringent carbon targets at the lowest cost. The natural gas combustion turbines were assumed to be "hydrogen ready" in that they could burn up to 30% green hydrogen at any point and ultimately be converted to burn 100% green hydrogen in the future. The **Shift portfolio** increased the renewables and battery builds to replace APS owned natural gas generation in the Bridge portfolio; natural gas tolling agreements were allowed to grow in the Shift portfolio. The **Accelerate portfolio** eliminated all future natural gas additions and increased the renewables and batteries significantly to meet future needs. No existing natural gas was assumed to retire by 2035 in the models.

In addition to the clean energy goal, all portfolios included APS's commitment to installing 850 MW of battery storage by 2025 with more storage added later. All portfolios also included the commitment to retiring Four Corners and Cholla coal plants in 2031 and 2025, respectively. APS did not consider earlier retirement dates in the models for either of the coal plants.

Table 7-6 on page 137 of the IRP provides a high-level comparison of the portfolio additions showing capacity by resource type. These are replicated below and are shown in MW.

Table 2: Capacities by resource type for APS portfolios

	Bridge	Shift	Accelerate	Tech Agnostic
Demand Side Management	1,602	1,602	1,602	1,602
Demand Response	693	743	793	693
Distributed Energy	1,585	1,585	1,585	1,585
Renewable Energy	6,450	7,950	10,375	750
Energy Storage	4,850	6,500	10,550	850
Merchant PPA/Hydrogen-ready CTs	1,859	1,135	0	5,115
Microgrid	131	131	6	281
TOTAL	17,170	19,646	24,911	10,876

APS included a 15% reserve margin in all portfolios. It tested this reserve margin with a resource adequacy model for the years 2020 to 2024 which is the window covering its action plan. Beyond 2024, when the portfolios become more dependent on renewables and batteries, it is not clear if the portfolios meet the industry standard "one day in ten years" loss of load event.

A summary of the portfolio results is shown in Table 7-8 on page 140 of the IRP. As expected, the Accelerate portfolio provides substantial gains in clean energy generation, carbon reductions, water use reduction and natural gas consumption. However, it is also significantly more expensive than the Bridge and Shift portfolios.

Table 3: Summary results of the APS portfolios

	Bridge	Shift	Accelerate	Tech Agnostic
Clean Energy	79%	84%	91%	52%
Renewable Energy	58%	66%	77%	21%
Revenue Requirement NPV 2020-2035 ($Billions)	26.6	26.9	28.4	24.9
System Cost Avg Annual Increase 2020-2035 (% per year)	1.3%	1.7%	2.8%	0.2%
Cumulative Capital Expense 2020-2035 ($Billions)	17.9	20.8	28.1	8.9
CO2 Emissions Reduction 2035 to 2005	69%	77%	86%	33%
Renewable Curtailment in 2035	17%	20%	23%	0%
Water Use in 2035 (1000 acre-ft)	36.0	33.6	30.2	42.5
Natural Gas Usage in 2035 (BCF)	74.0	53.9	27.3	176.7

APS performed sensitivity analyses on the portfolios by adjusting the natural gas price curve, carbon price curve and load growth forecast. The natural gas price sensitivity range went from a low case that is 23% below the base case to a high case that is 83% above the base case. Carbon prices ranged from zero to a curve that started at $19 per ton in 2025 and escalated at 7.5%. For the load forecast, APS ran the sensitivities required by the ACC: a zero-load growth and a load growth less than 1% (APS chose 0.9%).

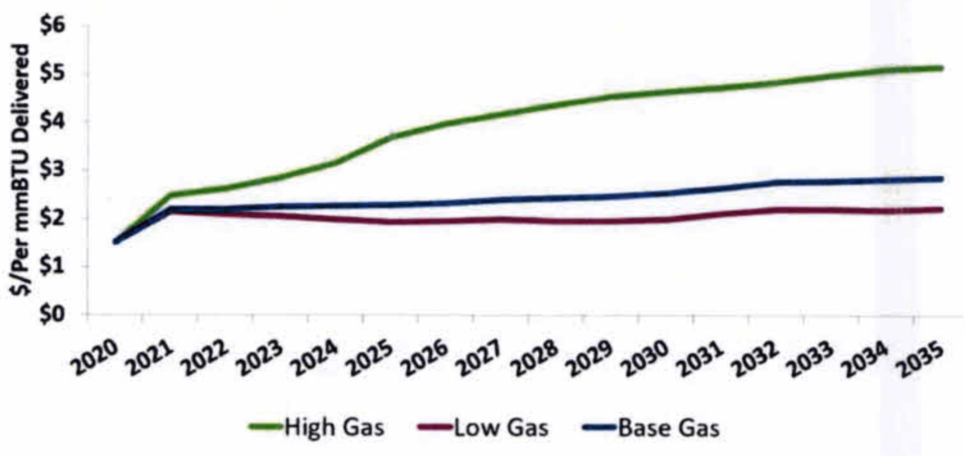


Figure 10: Natural gas price sensitivities

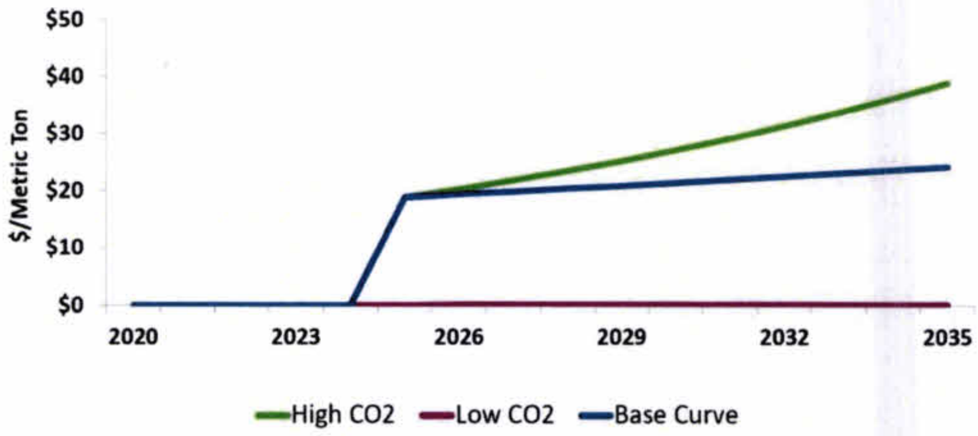


Figure 11: Carbon price sensitivities

This analysis showed that revenue requirements are sensitive to the three variables. The range of natural gas prices modeled caused revenue requirements to move up as much as 4% and down as much as 1%, for a potential swing of 5% depending on the future path. For context, the difference in revenue requirement between the Bridge portfolio and the Accelerate portfolio is 6.8% so an increase in 4% due to higher natural gas prices is significant. However, it is unlikely that natural gas prices will turn out to be 83% higher than APS expects.

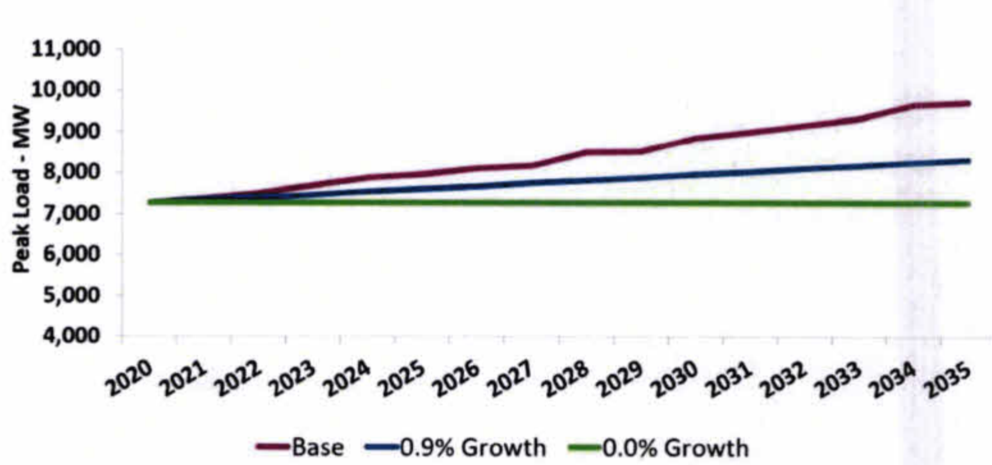


Figure 12: Load forecast sensitivities

Carbon prices were found to have less impact on revenue requirements. The range of carbon prices investigated resulted in the revenue requirement swinging from 3% below the base case to 0.4% above the base case. The large share of clean energy means that carbon price fluctuations will not affect operating costs significantly.

The load forecast sensitivity seems to be unrealistic given that APS believes load will grow at 2.5% annually. Model results based on zero load growth have no practical value because zero load growth is not a realistic projection at this time. The 0.9% projection, however, could be a realistic low growth case (assuming population declines) and shows that revenue requirements would be 5.3% lower if load grows at 0.9%.

APS feels that all three of the paths analyzed are viable options to move forward. Depending on the policy goals, APS could take an extremely aggressive path towards decarbonization or a more modest path. Either way, APS believes that it can meet stringent carbon reduction goals at a reasonable cost with any of the paths presented.

3.3.3 REVIEW OF MUST RUN ASSUMPTIONS FOR FOUR CORNERS POWER PLANT AND SOLANA PPA

On July 21, 2021, ACC Chairwoman Lea Marquez Peterson requested a review of the "must-run" assumptions on the Four Corners coal-fired power plant, which APS expects to retire after the expiration of the coal contract in 2031 as well as a review of the "must-run" assumption of the Solana concentrating solar power purchase agreement.

Regarding Four Corners she states:

> *As I understand from the stakeholders' filings, the primary concern is that failing to consider earlier decommissioning dates for the Four Corners Power Plant (inclusive of all costs associated with exercising early termination clauses and creating ratepayer-funded stranded assets) and replacing the plant's capacity with an equally reliable but significantly lower-cost resource (such as solar paired with battery storage) results in resource scenarios and portfolios that are not adequately represented or considered in APS's 2020 IRP. In particular, the stakeholders are concerned that failing to run a model representing such considerations would not allow the Commission to conclusively know which prospective resource mix could result in APS's "least cost" portfolio.*

Regarding the Solana PPA she states:

> *In filings made by one of the above-mentioned stakeholders on July 12 and 21 2021, it was revealed or otherwise alleged that APS knowingly entered into a 30-year PPA with a third-party power producer, Solar One, LLC, to procure above-market priced thermal solar power from Solana Generating Station at a rate of over four-times the levelized cost of energy in 2020 (the PPA, the "Solana PPA"). According to the stakeholder's filing, the Solana PPA is an issue because, according to the stakeholder, APS knew at the time of investment that the cost associated with the Solana PPA would be significantly higher than other sources of renewable energy and that ratepayers would be locked into this high price (even as the market cost of solar decreases) for at least a decade.*
>
> *Because the company was able to pass through the above-market costs of this PPA (about 14 cents per kWh) the stakeholder has alleged that ratepayers may have been paying an outrageous price for solar since the time of entering into the PPA, despite the fact that it was not the most prudent or cost-effective source. To substantiate the stakeholder's claims, the stakeholder has requested the Commission conduct an "external audit" of the pendency of the Solana PPA.9 Based on my understanding of utility PPAs, APS would plan to fulfill its contractual obligations with third parties and, thus, would be likely to apply a "must-run" assumption to its Solana PPA, as well...*
>
> *...In particular, it may prevent the Commission from knowing which prospective resource mix could truly represent APS's "least cost" portfolio, and it may result in ratepayers paying more than is reasonable and prudent, for longer than is reasonable and prudent, for equally reliable solar renewable energy that could be procured at a lower cost, all else being considered.*

The Chairwoman's Perspective then states:

> *Applying "must run" assumptions to the Four Corners and Solana resources may represent an approach that does not take into account all sources that can cost-effectively meet a utility's load forecast, and therefore could result in scenarios that do not truly represent the utility's "least cost" portfolio. Lacking this analysis would prevent the Commission from truly knowing which resource portfolios may balance the interests of reliability, affordability, and sustainability most effectively*
>
> *Accordingly, I would like Ascend Analytics to address in its report or a supplemental report the issue of APS's "must-run" assumptions on Four Corners and Solana by providing a brief narrative describing whether, in Ascend Analytics' sole discretion, APS's "must-run" assumptions result in portfolios or scenarios that, again in Ascend Analytics' sole discretion, are not adequately represented or considered in APS's RP. To be specific, this request is not a request for Ascend Analytics to run additional models. Rather, it is a request for Ascend Analytics to provide a brief narrative of the third-party consultant's independent opinion. In the interest of time, this opinion could be stated as simply as whether the third party-consultant believes the assumptions do or do not result in portfolios or scenarios that are or are not adequately reflected.*

Ascend Analysis of the Four Corners Must-Run Assumption

Ascend finds that the designation of "must run" for Four Corners is reasonable in the context of the planning principles outlined in Section 3.1, in which all decisions are not simply an optimization of any one factor but a balancing of the tradeoffs between multiple planning principles. In our opinion, it is likely true that the must-run constraint on Four Corners does not result in the least-cost portfolio. We also believe that APS should have shown a scenario in which Four Corners is retired prior to 2031 as a comparison point with the three proposed portfolio pathways. However, even if retiring the plant earlier could result in a lower cost portfolio, there are other valid reasons stemming system reliability as well as difficult contractual issues with co-owners of the plant.

APS is a co-owner of Four Corners with TEP, SRP, PNM, and NTEC (a Navajo Tribal Corporation). The co-owners have a contract with NTEC for a minimum coal delivery per year. The minimum uptake per year roughly translates to a 60 – 65% capacity factor of the power plant. Theoretically, APS could buy its way out of the contract before its expiration in 2031, but this would have to be a negotiated settlement between all the co-owners.

Setting aside the challenges of finding agreement between the ownership parties, issues around system reliability remain paramount. In the Rebuttal Testimony of Brad J. Albert on Behalf of Arizona Public Service Company[2], Mr. Albert expresses concern that the Western region is becoming too short on capacity to rely on generic market purchases.

> *I have little confidence that APS would be able to contract for reliable generating assets in the future. Over the past decade, thousands of MW of generation have been removed from the western market, either through retirement or utility purchase of the once large supply of merchant generation. Generation retirements for example include Four Corners Units 1-3, Cholla 2, Navajo Plant, and San Juan Units 2 and 3. California has retired San Onofre Nuclear Generating Station (SONGS) and many natural gas once*

[2] Staff Informal 3.1_APS16462_Brad Albert Testimony (AIII)_19-0235 Rate Case. REBUTTAL TESTIMONY OF BRAD J. ALBERT On Behalf of Arizona Public Service Company Docket No. E-01345A-19-0236

through cooling units. More retirements are anticipated in the next few years including Cholla 4 by the end of this year, followed by San Juan 1 and 4 in 2022, and Cholla 1 and 3 in 2025. The market is too tight to assume that it can provide for the reliable replacement of Four Corners 4 and 5 if they were to retire early.

He also states that solar and four-hour storage is not a one for one replacement for a base load coal plant.

If Four Corners were to retire before 2031, APS's share of Four Corners would likely need to be replaced by more than 1,000 MW of additional renewable generation plus 1,400 MW of battery energy storage on top of what is reflected in the IRP.

Ascend is not specifically commenting on Mr. Albert's assertions, although we find his concerns to be valid. Solar and four-hour duration storage does not provide the same services as a baseload coal plant. Coal plants provide energy around the clock and have a stable and reliable fuel supply, albeit coal plants generally have higher forced outage rates than solar and storage plants. A suitable clean energy replacement for Four Corners might also include wind, geothermal, and possible longer (8+ hours) duration storage. We agree that APS should not rely on generic market purchases given the situation Mr. Albert describes in the West in which legacy generation is rapidly closing and being replaced with weather driven renewable generation and energy duration limited storage resources. California is experiencing extremely tight capacity situation and generally relies on neighboring states to fill in the breach when load peaks during ever more frequent heat waves. Until such time as APS joins a future western wide balancing authority (otherwise known as a Western RTO), it is responsible for maintaining resource adequacy within its own service territory without relying on outside market purchases. It is not prima facie obvious that simply shutting down the plant by 2023 or as soon as practicable and replacing it with solar and storage is reliable or economic.

In the final analysis, we agree that this "scenario," an early retirement of Four Corners, should have been explicitly modeled. This scenario may even have been "least-cost". At the same time, APS could have also demonstrated that even if least-cost, that it would not be an acceptable portfolio if it failed to provide the necessary reliability performance. The best way to demonstrate this is using loss of load expectation analysis within the resource selection process to make sure all portfolios are comparable and meet the minimum criteria for reliability.

For the next IRP, we recommend APS explicitly models an earlier retirement date for four corners to demonstrate all aspects and implications of such a decision and more information will be available as to the performance of batteries to maintain system reliability from California.

Ascend Analysis of the Solana PPA

The Solana Generating Station is a 280 MW concentrating solar power plant developed by Arizona Solar One LLC (a subsidiary of Abengoa S.A). The PPA for Solana's generation was executed in 2008 with the goal of meeting Arizona's renewable energy standard (RES) of five percent of retail sales from renewable energy resources by 2012. In 2008, solar energy technology was in its infancy commercially speaking, so it was many times more expensive than it is today. At the time of the PPA execution, APS noted that the energy cost 19% above market[3]. According to the ACC Decision 70531, the PPA was selected through a competitive process and was deemed an

[3] Staff Informal 3.1_APS16453_Application for Approval of CSP

"appropriate component of APS' renewable energy portfolio and is compatible with APS' implementation plan as approved in Commission Decision No. 70313 [4]".

One can only evaluate a decision in the past using the information that was known at the time. In 2008, concentrating solar plants with molten salt storage were considered more cost-effective than solar photovoltaic technology. From today's perspective, the PPA contract is certainly badly "out-of-the-money" for renewable energy, however it is not reasonable to expect that APS should have known that at the time. A thirty-year term does mean taking on substantial risk that the asset would someday be highly uneconomic, however in 2008 renewable development was considered so risky by the finance community that these tenor lengths for off-take were required for the project to receive funding.

Directly addressing the Chairwoman's letter, the term, "must-take" is not applicable in this case in the same way it is for Four Corners. Solana has limited dispatchability and it does not have fuel cost. APS also does not own Solana; the contract is a power purchase agreement, whereby APS only pays the project owner for what energy gets delivered. Unfortunately, in hindsight this appears to be a bad contract for ratepayers, and perhaps more due diligence or more effort to negotiate a shorter-term length could make ratepayers better off. Nonetheless, APS is contractually obligated to take the energy under the terms of the agreement. Therefore, it is appropriate to model the resource in the portfolio as such.

3.3.4 REVIEW OF PREFERRED PORTFOLIO

APS did not specify a preferred portfolio. Instead, they developed an action plan based on the three portfolios they analyzed. The action plan covers the period from 2020 to 2024. The three portfolio models were nearly identical during the years 2020 to 2024 so APS can move along this path now while monitoring technology improvements to determine the optimal path in a future plan. Chapter 7 of the IRP, starting on page 157, covers the Action Plan for APS.

Demand Side

On the demand side, the action plan is built on continuing a high level of investment in demand side management, the energy efficiency plan focuses on measures contributing to peak reduction and the program dramatically increases programs designed to shift load through demand response and load management. The IRP states that demand response will contribute 193 MW of demand reduction from 2020 to 2024. This reflects a growing emphasis on demand response and load shifting programs. The distributed generation programs show slower growth during this period, potentially due to some programs being closed to additional enrollment (see page 161 of the IRP).

Supply Side

On the supply side, the Action Plan specifically covers expansion of renewable resources, increased energy storage, APS solar communities and growth in demand side resources. To meet the interim goal of 45% renewables by 2030, APS needs to add 300 – 400 MW of renewables annually through 2024. APS listed four outstanding requests for proposals (RFPs) covering 150 MW of solar plus storage, 150 MW of solar PV, 250 MW of wind, and 75 MW of demand response. APS will need to ramp up this effort to maintain the 300 – 400 MW of added capacity per year. To make the best use of renewables, APS has committed to procuring 850 MW of battery

[4] Staff Informal 3.1_APS16458_DECISION No 70531

storage by 2025. During the writing of the IRP, APS had paused the effort to expand energy storage due to the McMicken energy storage facility fire investigation. The pause forces APS to revise its battery project timelines which means APS will rely on short-term market purchases to meet summer peaking needs until battery capacity is ramped up.

Part of the action plan involves continued operation of certain existing resources. APS leases 42% of its share of Palo Verde nuclear facility through three separate agreements with the first agreement expiring in 2023 while the two remaining agreements expire in 2033. APS is committed to extending the Palo Verde leases. APS also plans to maintain its gas fleet during the transition to renewables. Natural gas generation provides firm capacity and reliability to APS, and natural gas prices are expected to remain low for the foreseeable future. APS did not specify details to transition away from natural gas over time.

Transmission improvements are a key part of enhancing reliability while growing renewables in APS. The 2020 – 2029 Transmission System Plan includes 26 miles of 230 kV lines, 3 miles of 115 kV lines and 38 new transformers. In total, APS plans to spend $590 million on transmission investments.

3.3.5 RECOMMENDATIONS TO IMPROVE IRP

Demand Side

Overall, there are not significant shortcomings with the load modeling and energy efficiency savings modeling in APS's IRP. APS maintains a substantial amount of detail and documentation to support their IRP. The energy efficiency forecast provided in the IRP and the supporting documents was inconsistent with the requirements of the energy rules. The energy rules, however, were finalized after the finalization of the IRP, so this inconsistency is not surprising.

Supporting information on the cost of the energy efficiency, distributed generation, and demand response programs would have been helpful to better understand how the increased demand response saving will be achieved. The details supplied on the most recent DSM potential study appear to indicate that maintaining energy efficiency savings consistent with the energy rules for an extended number of years may be difficult. Potential studies often show that energy efficiency savings can be shifted to occur into earlier time periods with aggressive programs (much like the energy rules), but without advancements in technologies (new technologies added to the study and to APS's DSM programs), it may be difficult to maintain an aggressive level of savings as opportunities become saturated.

Finally, more comprehensive and clear documentation would be helpful. It was difficult to connect the extensive data that was provided with the description of the plan in the IRP.

Supply Side

APS analyzed three portfolios to investigate three potential future paths with differing levels of renewables and energy storage. The portfolios were manually assembled with specific objectives in mind. The first recommendation to improve the IRP process is to use a capacity expansion model to determine the least cost combination of resources that would meet APS's future goals regarding clean energy generation and carbon emissions. The capacity expansion model approach also allows APS to run scenario analysis to show how the optimal resource selection changes with adjustments in on technology cost assumptions, load growth and carbon prices.

The production cost model input files indicate that APS included spinning and non-spinning reserves but did not include regulation up and down. The portfolios considered in this IRP contains vastly different amounts of renewables which drives the need to different levels of regulation to maintain operational reliability. Realistically, the amount of battery storage in the model is high enough to easily provide the necessary levels of regulation reserve to cover the variability from the high level of renewables. In a future IRP, APS should provide some context around the amount of regulation they currently use and the amount they expect to need to balance the high amount of renewables expected in the future. They should also include regulation in the production cost models to include the cost of serving regulation and energy from the dispatchable resources.

APS is a participant in the CAISO Energy Imbalance Market (EIM). The EIM provides APS with real-time access to wholesale energy trading at a five-minute time step. APS should include this in the IRP modeling instead of relying on hourly production cost models. When five-minute prices and dispatch are used in a production cost model, the value of flexible resources is revealed. The results would have shown significantly improved economics of energy storage relative to other resources. Batteries provide flexible capacity which can capture additional revenue in the EIM by ramping up and down in response to five-minute EIM prices. Real-time prices at the five-minute time step tend to be much more volatile than hourly prices, meaning that EIM prices will have large price spikes lasting a short period along with more frequent negative prices. Additionally, EIM access provides the ability to sell excess solar generation in the middle of the day which makes it an important aspect to APS operations that is neglected in hourly models.

The resource adequacy model shown in the IRP covered the years 2021 to 2024 and shows the APS portfolio to be reliable in the near term. APS used this model to determine whether a 15% reserve margin provided adequate capacity to meet future load. However, it appears that APS did not run a resource adequacy model for future years when it expects to have a much higher mix of variable energy from wind and solar. This does not mean the modeled portfolios are not adequate in the future years, but APS should confirm the reliability of the modeled portfolios going to 2035. This exercise would allow them to determine the proper amount of storage needed to maintain reliability with high levels of wind and solar expected. Additionally, APS should include the possibility of extreme weather affecting the resource adequacy as it did in the 2020 heat wave. Resource planning can no longer sample weather from the past and expect the future to be similar.

Power system operations are heavily dependent on weather which drives the load, renewable generation, and market prices. APS should consider using a model that uses weather to simulate load, renewable generation, and market prices. APS is on a path to a high level of renewable energy; they should consider modeling tools that can realistically replicate the dynamics of a high renewables system.

APS ran scenarios for the price of natural gas, price of carbon and the load growth in the sensitivity analyses. A key analysis that was missing is the sensitivity of market prices. High and low market prices will lead to vastly different outcomes that should be considered when making long-term resource plans. Including the market price sensitivity as part of capacity expansion models would add a lot of value to the analysis.

APS should consider alternative retirement scenarios for the coal resources. Keeping coal until 2031 without considering the possibility of an earlier retirement appears to be shortsighted given the frequency of coal closures in the WECC, mostly driven by economics. APS would serve ratepayers well by considering multiple options for transitioning out of coal.

Finally, the Technology Agnostic plan that APS showed as a benchmark provided no real value since it was not a realistic option for APS to build. Future IRPs should use a benchmark that meets minimum policy goals for clean energy or carbon emissions and show the least cost solution to meet the planning requirements.

3.4 REVIEW OF TEP AND UNSE IRPS

Tucson Electric Power and UNS Electric are owned by the same holding company and share the same resource planning staff. For the most part, the IRPs are highly similar, including using the same tools, inputs, and assumptions. For simplicity and to reduce unnecessary repetition, the following review includes both TEP and UNSE's IRPs. Differences between the two IRPs are specifically identified and discussed.

3.4.1 IRP PROCESS

TEP created an advisory council, consisting of customers, local government, and advocacy groups to guide the IRP process. The advisory council met once in 2019 and once in 2020. TEP discussed a range of topics in the Advisory Council meeting from load forecasting to resource costs and coal plant economics. While engaging with stakeholders is important in the IRP process there are key affected communities that were not part of the process, including any mention of working with Tribal Nations.

UNSE mentions stakeholder workshops in December 2019 in Lake Havasu City and Kingman but does not provide additional detail in its IRP. However, UNSE identified several governing themes from these workshops for their IRP process: recognizing declining costs of renewables and storage; avoiding large bets on long-term assets with uncertain futures; and maintaining affordability as UNSE transitions from reliance on the market to reliance on self-owned assets.

The IRP would have benefitted from a request for information to provide more detailed information on resource costs and availability. However, this concern is mitigated by UNSE's plan to procure future resources through all-source RFPs, which will ensure that resources will be procured with the best available current cost information at the time of procurement, rather than being locked-in to procurement decisions based on assumed costs that can quickly become outdated or inaccurate.

3.4.2 INPUTS AND ASSUMPTIONS

Demand Side

The consideration of supply side resources inherently requires an understanding of the projected energy and peak demand requirements. In the context of an IRP, this should extend to the various factors that affect both the amount and timing of consumption, which for this review the key resources were energy efficiency, demand response, distributed generation, and electrification.

For gross energy and peak demand, the IRPs provided forecasts by sector to 2035. The energy forecast for TEP increases from 8,970 GWh in 2020 to 11,721 GWh in 2035, with an average annual growth rate of 1.8%. The base forecast for peak demand shows growth from 2,589 MW in 2020 to 2,931 MW in 2035. The average annual growth rate of 0.8% is substantially lower than the energy forecast.

The electrification data for TEP consisted of a forecast of the annual energy associated with EVs, beginning with a total of 7 GWh and increasing to 786 GWh in 2035. Given the low starting point and anticipated adoption, the annual rate of this growth in these data varied greatly, starting at more than 200% per year and declining annually. The data provided by TEP show that by 2035, around 45% of TEPs residential customers will have an electric vehicle (assuming an annual consumption of 4,000 kWh). The peak demand for EVs assumed that most charging will occur off peak.

Both historically and in its forecast, TEP has only a small presence of peak demand savings from demand response. The 2020 DSM plan shows 41 MW of savings, representing about 1.6% of the system peak – increasing to 57 MW in 2050. Distributed generation from 2020 to 2035 shows incremental peak demand savings of 3 MW in 2020 increasing to 57 MW in 2050. Using the assumption that most of these savings are due to solar, they translate into 5.3 GWh of energy savings in 2020 increasing to 123 GWh in 2050. This represents a tiny amount of the potential for demand savings from technologies such as smart thermostats and behind-the-meter solar and storage. We believe demand response and DER adoption should be given more consideration in future IRPs.

The forecasts suggest reasonable rates of growth, but there are some shortcomings to the data. For one, while these forecasts account for the effects of the energy efficiency and distributed generation, though the amounts associated with these resources are not broken out. Additionally, the rate of growth for energy is markedly higher than peak demand, which is a discrepancy that merits more explanation. The inputs to these forecasts come from the various data sources used to develop the forecasts, which are laid out later in the discussion of modeling.

Energy efficiency is discussed sparingly in the IRP and concrete data are limited to tabular summaries of aggregate peak demand savings and a few graphical representations in the context of all sources of load. The bulk of the information on energy efficiency came in the data requests, but these have little information on the underlying assumptions. For example, one of the responses to the data request included a series of the combined energy efficiency and distributed generation that were incorporated into the energy forecast, making it difficult to assess them separately. It would have been better to review the utilities' energy efficiency potential studies, which would have provided an understanding of the technological, economic, and market factors underlying the projected energy efficiency resources, but these were not available for review.

Both IRPs also provided limited information on electrification. Electric vehicles are discussed generally in the IRPs, mostly in terms of global or national trends for adoption. The details on electric vehicles came in the responses to the data requests, where both utilities provided an annual series of the total energy. While the overall energy values are reasonable, the band is wide given the high uncertainty over adoption. Nevertheless, the series were provided with no underlying assumptions (type of fleet, numbers of cars, average annual consumption per car, etc.), which would have made it easier to determine the defensibility of the projections.

Demand response is similarly discussed in generalities as a resource for both TEP and UNSE and the IRP only presents its limited role in a few graphical representations, which show a small and apparently constant amount over the forecast horizon. Likewise, distributed generation is primarily discussed in general terms. Both IRPs anticipate slowing growth based on results from an econometric model, but the details are not provided.

Supply Side

Technology Costs:

The assumptions used by TEP and UNSE are generally reasonable and are shown in Figures 13-15. Capital cost assumptions for solar, wind, and storage all reflect future cost declines that are consistent with commonly used industry benchmarks, such as NREL Annual Technology Baseline (ATB) and Lazard. The capital cost assumptions are all significantly lower than the NREL ATB in absolute terms, with the solar capital costs particularly low. Given the history of renewable costs declining faster than most historical forecasts anticipated, the low capital costs assumed by TEP and UNSE are appropriate. However, the levelized cost of energy listed for solar and wind resources appears to be significantly higher than typical PPA prices available in the region, which are in the low \$20s per MWh. Given the potential for extensions of the investment tax credit (ITC), extension of the ITC to standalone storage, and safe-harbor provisions that allow resources coming online in later years to still qualify for earlier (higher) levels of the ITC, PPA prices will likely continue to be low when UNSE begins procuring resources. Ascend recommends that the commission ensure that all ownership structures are considered during resource procurement processes, with ownership-agnostic, least-cost options being pursued.

An additional note on technology costs is that the TEP and UNSE IRPs present cost assumptions for different resources in terms of the levelized cost of energy (LCOE) in Charts 26-30 of the TEP IRP and Tables 14-16 and Charts 14-16 of the UNSE IRP (shown here in figure 16). However, LCOE is a misleading metric, because it requires an assumed capacity factor for each resource, which may not reflect actual dispatch for thermal resources. LCOE also does not account for the different grid needs that are served by different resources. For example, for a peaking resource that operates infrequently, the capital cost is a more important metric than the LCOE, while for a resource that provides a large amount of energy, year-round LCOE may be more appropriate. Additionally, because storage does not generate energy at all but rather serves as a capacity resource, LCOE is an entirely inappropriate metric, and leads to counterintuitive outcomes such as implying that 8h storage is lower cost than 4h storage when it actually is ~70% more expensive.

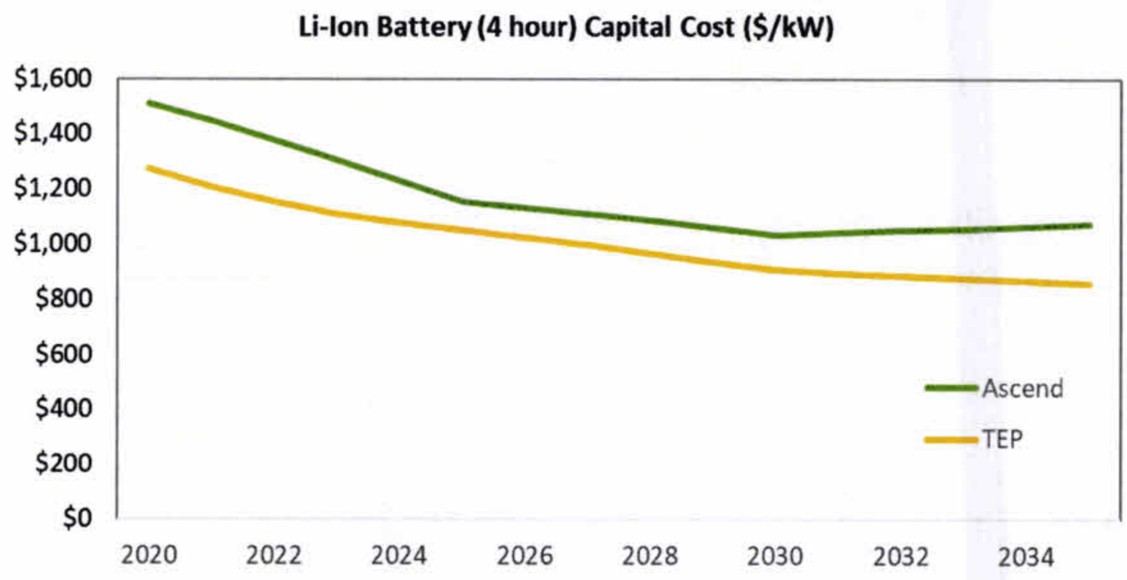


Figure 13: Capital cost comparison (li-ion 4-hour battery)

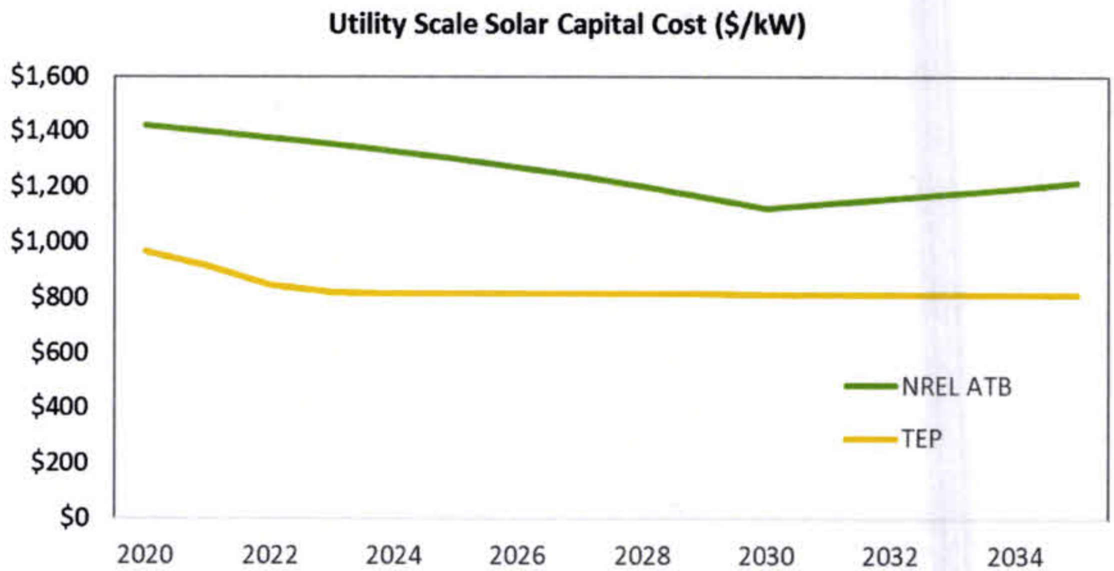


Figure 14: Capital cost comparison (utility scale solar PV)

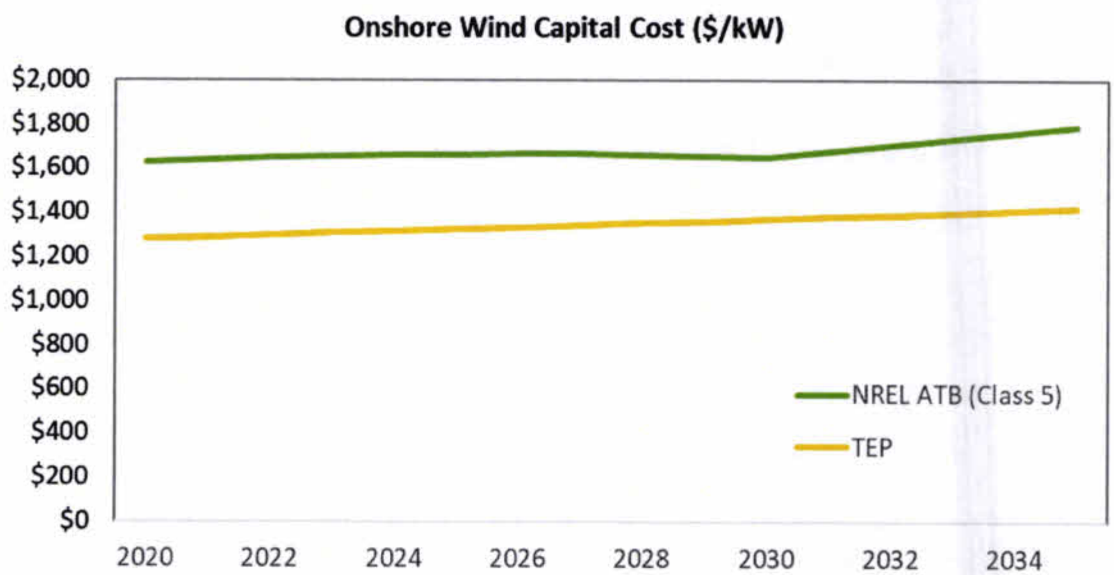


Figure 15: Capital cost comparison (onshore wind)

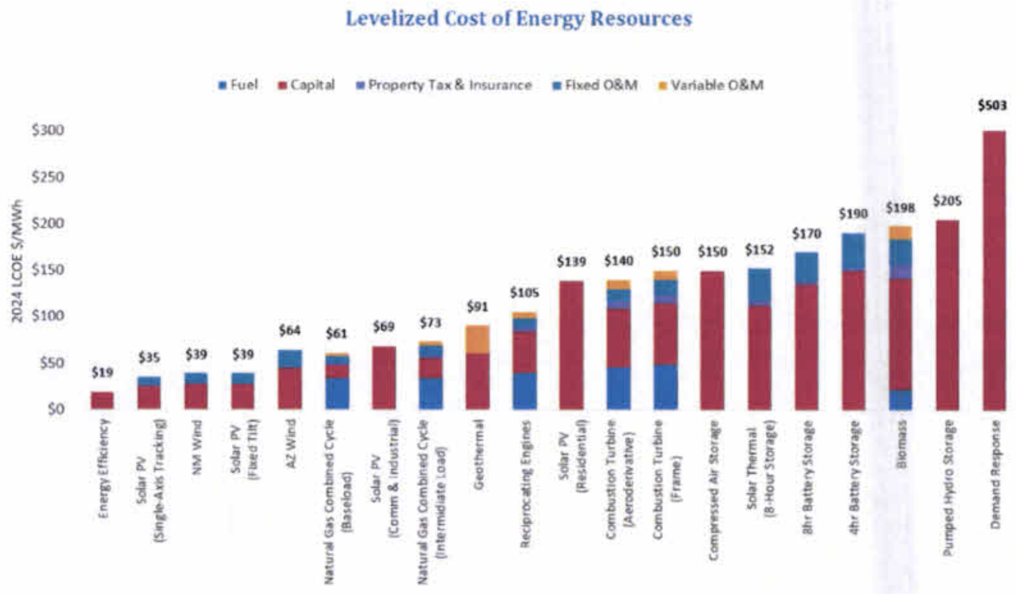


Figure 16: TEP IRP Levelized cost of energy per resource

Market Price Assumptions:

Market assumptions include power prices, gas prices, and market implied heat rates (power prices divided by gas prices). Implied heat rates function like a normalized power price that accounts for the impact of gas prices and are an indicator of whether gas generation resources can operate profitably in the market. As renewable energy sources contribute increasing shares of the electricity supply, they drive three critical changes in price dynamics. First, renewable energy with near-zero variable costs shifts the entire supply stack, leading to price depression. Second, this price depression is concentrated in hours with high renewable generation, leading to concentrated price depression during solar generating hours. Third, renewable intermittency leads to increasing price volatility, which creates value for flexible generation resources and risk for inflexible ones that are unable to quickly ramp or turn on/off in response to changing prices.

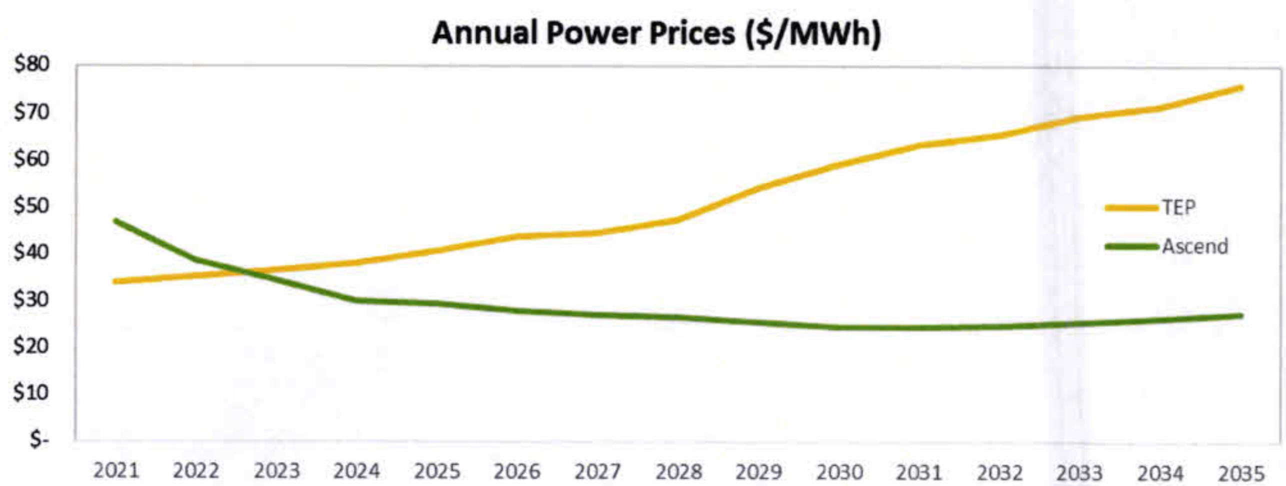


Figure 17: Palo Verde annual power price comparison

(Begin confidential information)

[Redacted due to confidentiality]

Figure 18: Palo Verde monthly power price comparison

(End confidential information)

The TEP and UNSE Palo Verde (PV) power prices take an hourly shape from E3 and scales it to a monthly price forecast that starts with the monthly market forwards from the Tullet Prebon index, which are then scaled by the Wood Mackenzie long-term price forecast for PV. While the incorporation of a price shape is critically important for long-term forecasts in an era of growing renewable penetration, the use of a price shape from a different vendor than the source of long-term forwards can lead to inconsistencies in the forecast. One result of this is that the implied heat rates are extremely high during non-solar hours in March (see Chart 31 of the TEP IRP and Chart 17 of the UNSE IRP), sitting at roughly 25 MMBTU/MWh while current off-peak heat rates are closer to 10, which is close to the heat rate of a typical new natural gas combustion turbine (NGCT). The implied heat rates are also high in general, staying between 15-20 MMBTU/MWh throughout the forecast, ***(Begin confidential information)*** *[Redacted due to confidentiality]* ***(End confidential information)***. These high heat rates may lead to overvaluing gas generation resources by overestimating their potential for market sales and overestimating their savings relative to market purchases. Such an overvaluation may shift the relative economics of gas capacity resources relative to storage or demand-side alternatives.

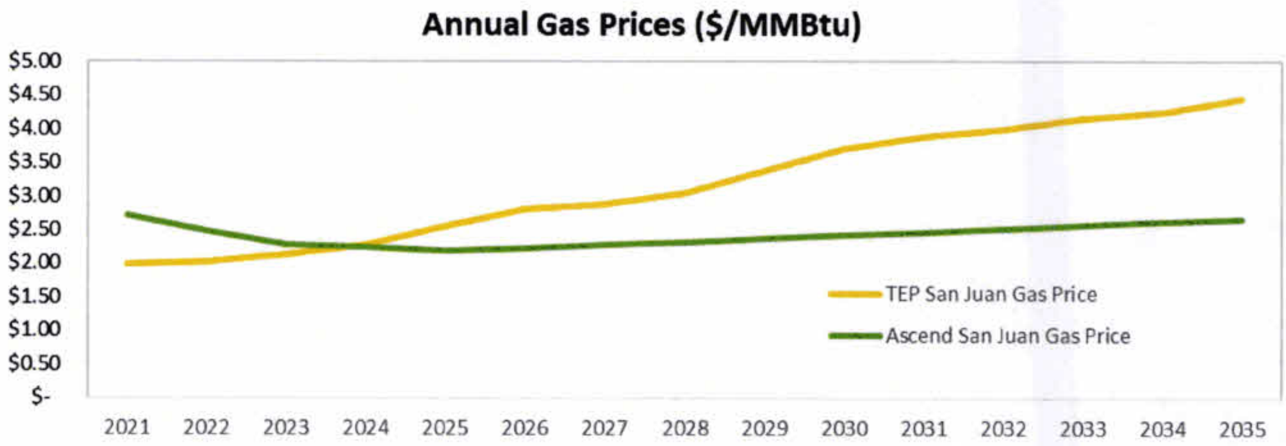


Figure 19: San Juan annual gas price comparison

(Begin confidential information)

[Redacted due to confidentiality]

Figure 20: San Juan monthly gas price comparison

(End confidential information)

The TEP and UNSE power prices are also high in general, climbing continuously throughout the forecast period, whereas Ascend's and APS's power price forecasts stay relatively flat in nominal terms. This high-power price forecast may lead to overvaluation of renewable resources, which could lead to a suboptimal procurement particularly of solar capacity as surplus solar generation continues to be built elsewhere in the Southwest US. With the climbing prices in TEP/UNSE's forecast, solar would appear economic throughout the forecast period, when it is likely to cease to be economic as the region becomes oversupplied during daylight hours.

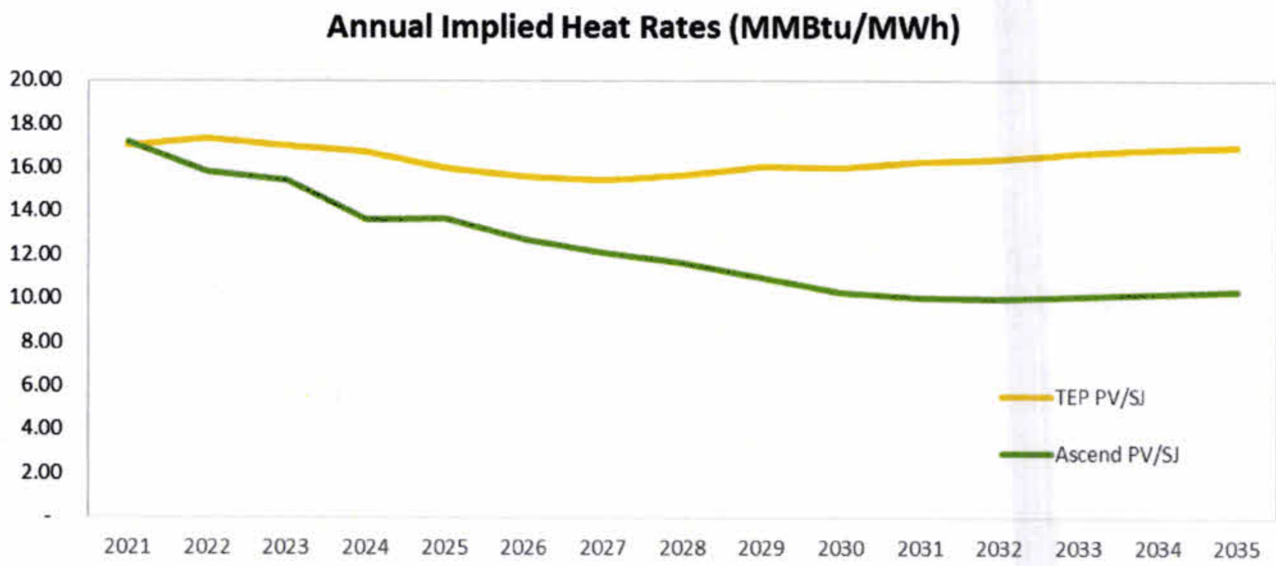


Figure 21: Annual implied heat rates, calculated as power price in Palo Verde divided by gas price in San Juan

(Begin confidential information)

[Redacted due to confidentiality]

Figure 22: Monthly implied heat rates, calculated as power price in Palo Verde divided by gas price in San Juan

(End confidential information)

(Begin confidential information) *[Redacted due to confidentiality]* ***(End confidential information).*** The assumed carbon prices are reasonable given the lack of a national or state carbon market for Arizona, reflecting the uncertainty of potential futures with and without a carbon price.

3.4.3 MODELING APPROACH

Demand Side

For the demand side, the modeling approaches consisted primarily of the methods used to develop the energy and demand forecasts. TEP's and UNSE's IRPs do have some information on the forecasts, but the important details are presented in a supplemental load forecast update. This update applied to both TEP and UNSE, as they share the same forecast methods.

Overall, the methods described are indicative of a quality forecasting approach. They conform to a variety of standard industry practices, each appropriate for its respective sector. The residential and commercial sector forecasts are based on a combination of a use-per-customer forecast and a customer forecast, each relying on ARIMA models with exogenous variables. The two forecasts are multiplied to generate the total sales. While not the most common approach, this hybrid method helps the utilities better isolate the account for how energy efficiency and distributed generation influence net retail sales versus gross consumption. The customer forecasts assess a variety of models using intuitive drivers (e.g. population, commercial establishment growth) and accounts for weather and calendar effects. Final model selection considers the out-of-sample performance of the candidate models. For these load forecasts, the IRP relied on a variety of reliable sources for their data, including IHS Global Insight, The University of Arizona Forecasting Project, Arizona Department of Commerce, the U.S. Census Bureau, and the National Oceanic and Atmospheric Administration (NOAA).

Peak demand is forecasted using a model that combines weather and sales data to estimate the peak demand. While this approach has worked well historically, a potential future shortcoming in this approach is an inability to anticipate how demand side resources might shift both the magnitude and timing of peak demand. The peak demand forecast provides little information on the typical timing of system peaks, and thus there is not sufficient data to determine how relevant this might be for these two utilities.

For energy efficiency, demand response, electrification, and distributed generation, there was no information provided on the modeling approach and the assumptions used to generate the forecast presented in the IRP or in other supporting documents from the data request.

Supply Side

The portfolios presented in the TEP and UNSE 2020 IRPs were hand-designed with the energy rules draft in mind, and in the case of UNSE with the intention to reduce reliance on market purchases of capacity. Capacity expansion models were not used for resource selection and the team hired Siemens to run the reliability analysis of these portfolios, which was based on the ability of the portfolio to meet four criteria:

- Supply sufficient energy at the net peak load
- Meet 3-hour ramp requirements
- Meet 10-minute ramp requirements
- Minimize overgeneration from renewable assets

Siemens ran Monte Carlo simulations of the combined TEP and UNSE system to determine the maximum net load as well as maximum 3-hour and 10-minute net load ramps. These results were then compared against the portfolio's firm generation and ramping capabilities. However, the reliability study did not simulate forced outages (instead just derating the thermal generation) or consider available battery state of charge and consecutive hours at high net load. These factors play a critical role in understanding reliability in a renewable/storage-heavy portfolio, and their exclusion will likely lead to designing portfolios that are less reliable in operation than they are in the model.

TEP provides a qualitative discussion of the ancillary services in Chapter 3. The modeling done by TEP in the IRP process included operating reserves equal to 6.5% of firm load but did not include intra-hour products such as frequency or regulation. The UNSE IRP does not discuss ancillary services except to say that ancillary services are provided by TEP through becoming part of the TEP balancing authority.

TEP and USNE did not model sub-hourly dispatch of their generation as part of the IRP modeling. Though both IRPs discuss participation in the CAISO Energy Imbalance Market (EIM), such future or potential participation is not incorporated in the IRP modeling.

Best-practice in resource planning involves optimized capacity expansion models that select the most economic resources subject to defined constraints, such as emissions targets and minimum/maximum resource quantities. While the portfolios in both the TEP and UNSE IRPs were hand-designed instead of optimized, this approach was reasonable given the various requirements of the draft energy rules, the requirements of Decision 76632, and requests from the TEP and USNE Advisory Councils. Knowledge of the costs of the supply resource options and expert judgement can yield a well-reasoned portfolio, particularly when there are several prescribed requirements as in the draft energy rules.

Best-practice in resource planning also involves considering a portfolio that will be robust against a variety of unknown future conditions rather than being optimized for a single simulation or set of assumptions. The portfolio cost assessment did include portfolio costs across 50 stochastic simulations with correlated uncertainty in the load, gas prices, and power prices. TEP and UNSE both demonstrated that their preferred portfolios were consistently among the least cost portfolio across the range of simulated conditions (see Appendix D of the TEP IRP and Appendix A of the UNSE IRP). However, the simulations did not include correlations with renewable generation or forced outages, which can better identify the critical events under which the system is at its limits. The critical load balancing conditions can be very different when load and renewable generation are appropriately correlated: weather conditions that drive coincident high load and high renewable generation create very different system conditions than weather conditions with high load and low renewable generation.

Best-practices also involve considering the sub-hourly (real-time) attributes of flexible resources in assessing their value to the system. In markets with real-time price signals, such as the EIM, this value is evidenced via high price spikes when the system requires resource flexibility. Given that TEP is joining the EIM in April 2022, and UNSE may follow, the potential revenue for flexible resources should be accounted for in portfolio modeling. Batteries and RICE units, which have short startup times, high ramp rates, and no startup costs often exhibit much higher value when considering real-time grid needs rather than hourly dynamics alone. This value of flexibility is increasing as energy supplies incorporate increasing shares of renewable generation.

3.4.4 REVIEW OF TEP PREFERRED PORTFOLIO

Demand Side

Supply side resources are the emphasis of TEP's preferred portfolios. For the demand side inputs, TEP's preferred portfolio only had annual projections for the energy efficiency savings out to 2035. These series represented savings compliant with the energy rules. Beyond that, the preferred portfolio consisted of one data point of a projected peak reduction of 90 MW associated with distributed generation solar. The available data shows a flat curve and limited information about demand response throughout the forecast horizon, roughly equivalent to the 41 MW of annual reductions described in TEP's DSM plan.

Supply Side

TEP's preferred portfolio adds 1,500 MW of single-axis tracking solar, 500 MW of wind, and 1,400 MW of new 4-hour storage by 2035, while retiring Springerville 1 and 2 in 2027 and 2032 respectively. It has the Springerville units running seasonally from the mid-2020s until their retirement.

The expected portfolio solar/wind ratio of 2:1 is reasonable given the expected lower cost of solar and better alignment of solar generation with load profiles. Adding renewable generation and storage through the IRP period aligns with TEP's goal of increasing resource diversity, especially when considering the new gas generation that came online just before the start of the IRP.

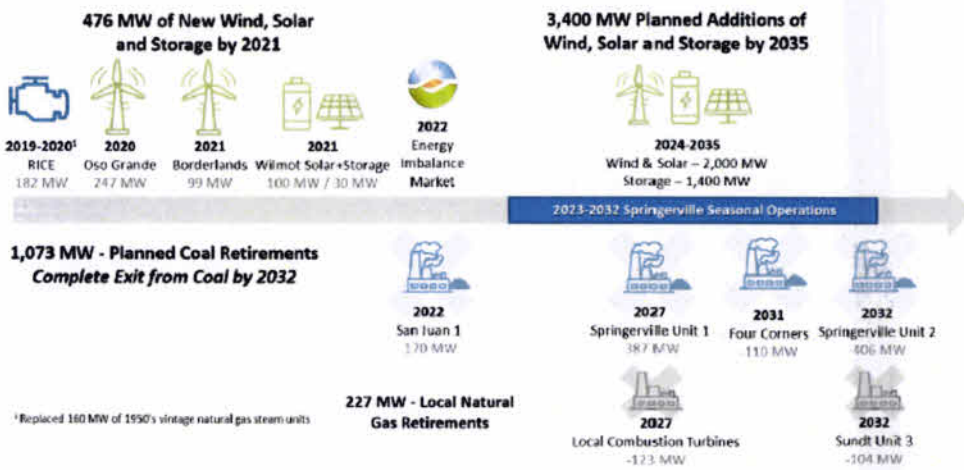


Figure 23: TEP Portfolio Evolution (Chart 56 of IRP)

3.4.5 REVIEW OF UNSE PREFERRED PORTFOLIO

Demand Side

UNSE's preferred portfolio focuses on supply side resources. The available data show only graphical representations of these resources (see Figure 24). While energy efficiency does show annual increases, both distributed generation and demand response are both small in magnitude and static over time. Note that originally, the UNSE believed itself exempt from the energy rules, but later provided a series of energy efficiency savings that were compliant.

Supply Side

UNSE's reference portfolio, shown in figure 24, involves keeping all existing thermal resources online while adding 150MW of solar generation, 115 MW of wind generation, 70MW of storage, 100 MW of RICE units, 4% annual growth in demand response, and growth in energy efficiency consistent with the draft energy rules.

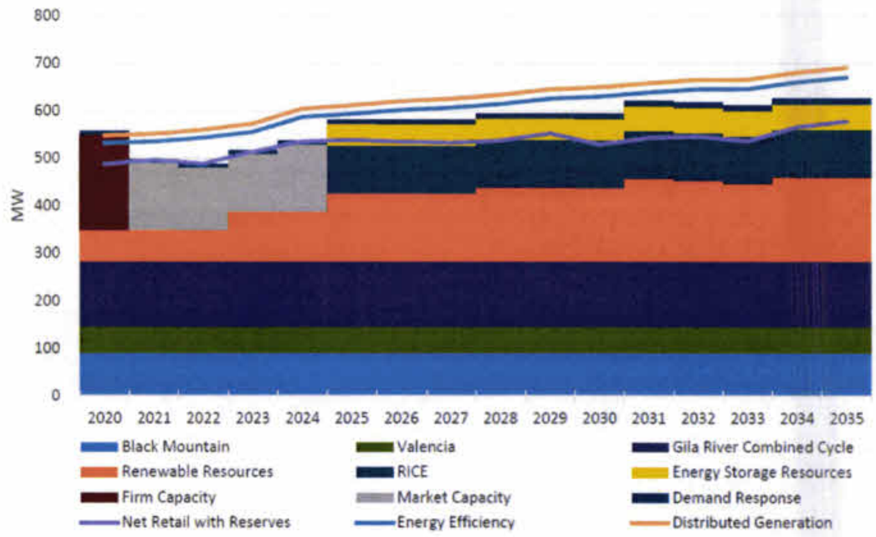


Figure 24: UNSE Preferred Portfolio Capacity Mix (Chart 35 in IRP)

Given UNSE's goal of moving toward less reliance on market capacity, the reference portfolio is a reasonable path forward. The bulk of the new supply resources are expected to be renewable energy and energy efficiency, while the capacity additions that serve reliability needs are flexible resources that are the appropriate complement to a rapidly increasing renewable penetration. The expected portfolio solar/wind ratio of 2:1 is reasonable given the expected lower cost of solar and better alignment of solar generation with load profiles. Figure 25 shows renewable energy supplying roughly half of net demand in 2035, and the RICE and storage units have the requisite flexibility to accommodate the intermittency of renewables. Additionally, UNSE's current shortage of capacity creates a need to acquire firm capacity, justifying the larger quantity of RICE units than storage. UNSE should continue to monitor the economic outlook for the Gila River NGCC, as its economic viability is likely to decline if its capacity factor declines with market prices and increasing shares of energy generation coming from low-cost renewable sources.

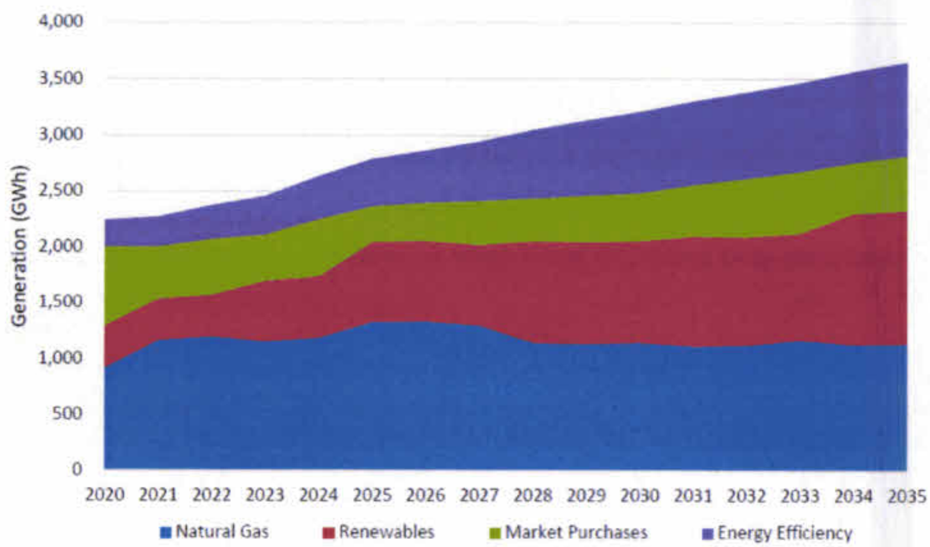


Figure 25: UNSE Preferred Portfolio Energy Mix (Chart 34 in IRP)

Because actual acquisitions will be pursued through an all-source RFP, the mixture of solar and wind supply should be adjusted as future resource costs evolve, opportunities emerge to procure refurbished firm capacity resources at low costs, and additional energy efficiency gains may become prohibitively expensive as energy codes become more rigorous and low-hanging-fruit opportunities diminish. UNSE should also continually assess its needs relative to the market and focus on procuring resources that complement the existing supply in the region. For example, if the region becomes oversupplied with solar generation independently of UNSE, UNSE should consider increasing its acquisitions of storage or wind instead. Thus, while the reference portfolio is a reasonable path forward given current market conditions and expectations, new resources should be strategically acquired in reflection of the evolving supply conditions and market context in Arizona in general.

3.4.6 RECOMMENDATIONS TO IMPROVE IRP

Demand Side

While the content of the IRP is generally reasonable, the primary opportunity for improvement for both TEP's and UNSE's IRPs would be additional granularity to the reported data and more supporting documentation for the data and methods used to create the demand side resource values. Only the energy and peak demand forecasts had a supporting document that clearly outlined the data and methods, but it would be helpful to have similar documentation of the efforts to develop data for the other resources.

One example of how the data provided lacked important granularity was the load growth due to electrification. Ignoring that EVs were the only explicitly considered source of load growth, the only information was an annual total kWh value. To understand this forecast and extend it to 2050, the analysis would have been improved with more information on the underlying assumptions, such as the number of vehicle or customers and the annual consumption per vehicle. Furthermore, there was no information to break out whether the energy was due to residential customers or commercial fleets.

Another area that would have benefited from more details was energy efficiency. In general, a better understanding of the measures or end uses contributing to the savings would help to create better estimates of peak impacts and costs. Furthermore, one of the series of energy efficiency savings provided as part of the response to the data request was inclusive of distributed generation, further complicating efforts to assess the inputs. These data were likely provided in TEP's and UNSE's energy efficiency potential studies, but this report was not available.

Finally, given the uncertainty with forecasting in general, it is understandable that the IRP forecasts did not go to 2050. Nevertheless, had the original forecast been extended 15 years, it would have at least ensured consistent forecast drivers throughout forecast horizon. Likewise, based on the relatively incongruent historical and forecasted growth rates, it would have been helpful to have more information to better understand the drivers underlying this inconsistency.

Supply Side

TEP and UNSE should begin accounting for sub-hourly value of their resources. Accounting for the needs for and value of real-time flexibility is becoming increasingly important in resource planning as renewable penetrations grow and volatility increases in both supply and net demand. Resource planning that only considers hourly time intervals increasingly obscures the sub-hourly dynamics that both create economic costs/revenues and also lead to supply shortages. Given that TEP is joining the EIM in April 2022, and UNSE may follow, resource procurement must account for the value that flexible resources provide at the sub-hourly level in this market. This value can be accounted for either by simulating real time prices and dispatch, or by calculating a 'sub-hourly credit' that varies across resource types according to their flexibility and accounts for this flexibility value.

TEP and UNSE should study resource adequacy, reliability, and loss of load conditions in greater depth. Resource planning in an era of high renewable penetrations must account for the influence of weather on loss-of-load events. Accounting for correlations between weather, load, renewable generation, and forced outages is critical for identifying the critical conditions under which net demand peaks. Moreover, as solar generation is increasingly added to the system, the net load peak shifts towards sunset, leading to a near-zero capacity value for solar generation. To properly account for these conditions, reliability studies should at a minimum simulate forced outages, correlated load and renewable generation, and storage state of charge to assess Loss of Load Hours (LOLH) or Loss of Load Events (LOLE) and calculate the Effective Load Carrying Capability (ELCC) of different resources that are added to the portfolio. Planning using a simple reserve margin and capacity targets will become increasingly insufficient as the TEP and UNSE portfolios become increasingly supplied by renewable and duration-limited (i.e. storage) resources. Planning must focus on procuring the resources that meet the critical needs for the system and when those critical conditions occur.

TEP and UNSE should implement optimization software in its capacity expansion planning. While hand-designed portfolios can be appropriate for meeting a complex set of constraints, such as meeting the draft energy rules, the changing dynamics of market prices, the value of energy, and net load shapes make it increasingly difficult to hand-design portfolios that will be optimal for a changing and evolving future. A capacity expansion approach that automatically optimizes resource acquisition subject to specified constraints should be implemented in future planning activities.

TEP and UNSE should consider using a model which simulates weather, load, and market prices. Power system operations are heavily dependent on weather which drives the load, renewable generation, and market prices. TEP and UNSE should consider using a model that uses weather to simulate load, renewable generation, and market prices. TEP and UNSE are on a path to a high level of renewable energy; they should consider modeling tools that can realistically replicate the dynamics of a high renewables system.

4 Assessment of Proposed Energy Rules Cost

The following sections detail a cost analysis of the proposed Energy Rules, with targets of 100% and 80% clean energy by 2050 as well as a "least cost" case. The results show a comparison of the total costs of the "Energy Rules" cases minus the "Least-Cost" case. Costs include new capital expenditure, operating expenses, fuel, purchased power, stranded costs, and transmission access costs.

The "Least-Cost" portfolio is not easy to define without the time to perform a full capacity expansion analysis. In hand-designing the portfolios, we interpreted the "Least-Cost" portfolios as having the implicit assumption that traditional resources such as natural gas power plants are "least-cost" for providing firm capacity. Therefore, our "Least Cost" portfolios follow a more traditional approach to resource acquisition, which includes natural gas turbines for capacity, less energy efficiency savings in the future (as cost-effective EE gets harder to find and implement), and more renewables. Any portfolio without GHG constraints would still add renewable energy because it is now widely considered the least-cost source of bulk system energy. In contrast, the "Energy Rules" portfolios do not add new gas but instead rely on storage and renewables to replace retiring coal and gas. For the 100% clean energy portfolio, existing gas infrastructure were converted to burn renewable fuels such as green hydrogen between 2040 and 2050.

The analysis was performed by the utilities themselves with the production cost model Aurora. Although Aurora has a capacity expansion capability, we did not request the utilities use it because capacity expansion modeling requires a significant time investment in the specification of constraints, analysis, and re-running of the model to get the results. Although APS used capacity expansion modeling in their process, TEP and UNSE hand-designed portfolios and were not immediately set up to perform capacity expansion modeling.

4.1 APS

4.1.1 APPROACH

APS estimated the cost of implementing the Energy Rules by calculating the revenue requirements for a least cost scenario, a scenario where APS meets the 80% carbon reduction target by 2050, and a scenario where APS eliminates all carbon emissions by 2050. The least cost scenario provided a reference case to benchmark the Energy Rules costs. APS used the Technology Agnostic portfolio from the IRP, extended to 2050, as the least cost scenario for the Energy Rules analysis. The Shift portfolio provides the basis to build the Energy Rules 80% and Energy Rules 100% portfolios. To meet the 80% carbon emissions goal by 2050, APS made minor adjustments to the Shift portfolio since it was found to reduce emissions 77% by 2035. The Energy Rules 100% portfolio had significantly more clean energy and energy storage additions to reach full decarbonization by 2050. APS ran the three scenarios with the same inputs and assumptions used in the IRP and also using custom inputs provided by Ascend that specified alternative projections for gas and power market prices and technology costs.

In extending the models to 2050, APS performed reliability checks and made necessary adjustments to ensure the portfolios could adequately serve customer load. APS did not run a new resource adequacy model on the portfolios, instead they used previous modeling outputs to estimate the capacity contribution of future wind, solar and battery storage resources. Given the time constraints, this approach seemed satisfactory for the models.

Finally, APS ran a small set of sensitivity runs to determine how the assumed prices of natural gas and carbon emissions would change the outputs.

4.1.2 INPUTS AND ASSUMPTIONS

Demand Side

The assessment of the energy rules necessitates developing forecasts for base load and peak demand, as well as other demand side resources such as energy efficiency, demand response, and distributed generation. This entailed reviewing various data sources and leveraging existing studies to extend the forecast to 2050. The remainder of this section describes the creation of these series.

APS Base Forecast: In the available data, the energy forecast for APS increases from 28,905 GWh in 2020 to 47,448 GWh in 2035. The annual growth rate between 2020 and 2021 is approximately 4.1%, falling to 2.5% between 2034 and 2035. The annual growth rate in the APS baseload forecast is 2.5% between 2034 and 2035. The base forecast of energy from 2036 to 2050 assumes the 2.5% growth rate continues, with the 2050 base forecast of 68,718 GWh. As stated previously, the forecast was reviewed by Itron, and then further updated by APS to improve the IRP forecast.

The base forecast for peak demand shows growth from 7,470 MW in 2020 to 11,271 MW in 2035. The annual peak demand growth rate in 2020 is 2.41% substantially lower than the energy forecast. The annual peak demand growth rate between 2034 and 2035 is 2.37%, very similar to the 2020 peak demand growth rate and the energy growth rate during this period. The annual peak demand growth rate between 2034 and 2035 is 2.37%.

APS Electrification: The electrification data provided by APS included base, transformative, and blended EV adoption scenarios. The APS EV forecast for 2019 estimated annual usage at 40 GWh growing to 56 GWh in 2020. The APS EV usage is forecast through 2038, where annual usage if forecast to be 1,714 GWh. Verdant assumed that the 40 GWh was in the base usage forecast and began the 2020 base forecast for EV and electrification usage at 8 GWh. For 2038, the Verdant EV and electrification forecast is slightly higher than APS's original forecast. APS's forecast was 1,715 GWh while the Verdant base forecast is 1,815 GWh. Both forecasts project an addition of over 300,000 EVs from 2020 to 2035. The growth rate in electrification energy use exceeded 100% during the early 2020s, declining to under 20% by 2035. Verdant assumed a continued growth in EVs, forecasting more than one million EV in APS territory by 2050, with an energy consumption of 4,805 GWh. The extrapolation of these data to 2050 was more challenging given the high degree of uncertainty regarding EV adoption.

APS Energy Efficiency: APS's IRP did not include the required forecast of energy efficiency savings consistent with the Energy Rules. The APS 2021 DSM plan, however, has a target of approximately 335,000 MWh of annual energy savings from efficiency measures while the APS Energy Consumption by Month and Customer Class listed an incremental 2021 energy efficiency program saving of approximately 175,000 MWh. The targeted energy savings in the 2021 DSM plan, closely approximates the energy efficiency savings necessary to meet the aggressive energy rule targets. Given the difference in the two 2021 incremental energy efficiency values, they were used as the basis for two different energy efficiency forecasts. The higher 2021 value was used to develop a forecast of energy efficiency savings for the Energy Rules portfolio while the lower 2021 value was used for the Low-Cost portfolio. The energy efficiency for both the energy efficiency rules and the low-cost portfolio begin with the IRP's initial forecast of 210,664 MWh of energy efficiency savings in 2020.

For the Energy Rules energy efficiency forecast, the incremental energy efficiency savings grow at the same rate as the base energy forecast. This approach maintains the required relationship between energy efficiency savings and the base energy forecast. The cumulative energy efficiency savings recognizes that approximately 20% of APS energy efficiency savings are derived from behavioral programs with a one year expected useful live. While it is assumed that APS continues to offer these programs, the accumulation of savings assumes that the behavioral savings from the previous year program are not maintained. In the Energy Rules scenario, the cumulative energy efficiency savings are 5,318 GWh in 2035 and 12,028 GWh in 2050. The Low-Cost portfolio cumulative energy efficiency savings are 2,836 GWh in 2035 and 5,461 GWh in 2050. The Low-Cost portfolio savings are consistent with APS's IRP plans and reflect incremental energy efficiency savings of 175,000 MWh annually.

The energy efficiency demand savings for the Energy Rules and the Low-Cost portfolio were developed similar to the energy savings. The 2020 demand savings for both portfolios begin with the 2020 IRP number, 105 MW. In 2021 the Energy Rules portfolio uses the incremental demand savings from the 2021 DSM plan, 132 MW for a 2021 cumulative demand savings of 216 MW. The Low-Cost portfolio cumulative demand savings in 2021 is 189 MW. In 2035 the Energy Rules demand savings are 2,006 MW, growing to 4,484 by 2050. The Low-Cost portfolio demand savings are forecast at 1,207 in 2035 and 3,098 in 2050.

APS Demand Response: The demand response programs are assumed to have demand savings but no energy savings. In 2020, both the energy rules and the low-cost portfolio have 21 MW of demand response savings. These savings are consistent with those presented in the bridge portfolio. For the Low-Cost portfolio, the demand response program follows the trajectory of the bridge portfolio, growing to 337 MW in 2035. The Energy Rules portfolio has a larger increase in demand response between 2020 and 2021 due to the planned demand response savings in the 2021 DSM plans. The 2021 demand response savings in the Energy Rules portfolio is 116 MW compared to 62 MW in the least cost portfolio. For the low-cost portfolio, the demand response program follows the trajectory of the bridge portfolio, growing to 337 MW in 2035. The Energy Rules portfolio has a more rapid increase in the early years of the forecast period (representing a significant increase in DR programs in 2021), but this portfolio also grows to 337 MW in 2035. The Energy Rules portfolio grows to 691 MW in 2050 while the Low-Cost portfolio grows slightly less to 608 MW.

APS Distributed Generation: For both energy rules and low-cost scenarios, distributed generation series are based on the bridge portfolio. The energy and demand savings in 2020 are 192 GWh and 4 MW. These are projected to grow to 2,670 GWh and 225 MW by 2035. These are projected to grow to 2,670 GWh and 225 MW by 2035. The 2050 savings represent a linear extrapolation of savings reaching 5,535 GWh and 633 MW.

Supply Side

APS used the Technology Agnostic model for its least cost reference in the analysis of the Energy Rules. For the carbon reduction cases, 80% and 100% reduction, APS used the Shift portfolio since this portfolio achieved nearly 77% carbon reductions in 2035 putting it on a path to reach 80% reduction by 2050. APS also used the Shift portfolio as a starting point for the 100% carbon reduction by 2050 scenario. The table below shows the portfolio capacity by resource type. The Energy Rules portfolios rely much more on renewables and energy storage while the least cost portfolio adds a lot of natural gas capacity. APS used the same portfolios for the APS and Ascend assumptions.

Table 4: APS Portfolio Capacity by Resource Type – Both APS and Ascend Assumptions

	Least Cost			Energy Rules 80%			Energy Rules 100%		
	2030	2040	2050	2030	2040	2050	2030	2040	2050
Natural Gas	6,923	9,093	11,807	4,933	5,295	4,730	4,933	5,295	-
Coal	970	-	-	970	-	-	970	-	-
Nuclear	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146
Solar	717	1,549	2,645	2,417	6,024	9,120	2,417	7,074	7,570
Wind	647	600	2,250	1,597	2,400	4,300	1,597	2,600	3,300
Geothermal	-	-	-	-	-	250	-	-	250
Biomass	3	-	-	3	-	-	3	-	-
Storage (4 hours)	552	1,400	1,850	1,702	3,550	3,400	1,702	3,550	5,000
Storage (8 hours)	-	-	-	-	1,250	1,250	-	1,250	5,000
Storage (12 hours)	-	-	-	-	200	3,500	-	1,000	3,500
Microgrid	263	313	313	88	163	163	88	163	163
Market Purchases	160	160	160	160	160	160	160	160	160
Renewable Fuels	-	-	-	-	-	-	-	-	4,706

As expected, the carbon emissions drop considerably for the two Energy Rules portfolios.

Table 5: CO_2 Emissions in millions of metric tons

	2030	2040	2050
Least Cost	12.4	10.9	12.9
Energy Rules 80%	9.1	3.8	2.2
Energy Rules 100%	9.1	2.7	0

Carbon emissions in 2005 were 16.6 million metric tons which is the reference year for the 80% reduction goal. The carbon emissions in 2050 with the updated Energy Rules must be less than 3.32 million metric tons. APS modeling shows the Shift portfolio extended to 2050 can achieve 86% reduction.

4.1.3 RESULTS

The cost of transitioning to a clean energy system was determined by the increased revenue requirement for the clean portfolio compared to the least cost portfolio. As the following charts indicate, the cost to achieve a fully decarbonized grid is much higher than the 80% reduction scenario. However, cost estimates beyond 2030 are very speculative and should be taken as rough estimates. Technological advances in energy storage will be an important driver in costs for future grid operations, and at this point, energy storage is rapidly changing.

The results of the analysis for APS are shown in the following tables:

Table 6: Revenue Requirement ($M) - Utility Assumptions

	2025	2030	2035	2040	2050
100% Clean	2,865	3,419	3,831	4,294	7,342
80% Clean	2,865	3,419	3,832	3,919	5,657
Least Cost	2,796	3,118	3,272	3,307	4,650
Difference (100% Clean – Least Cost)	69	301	560	987	2,692
Difference (80% Clean – Least Cost)	69	301	560	612	1,008
% Difference (100% Clean – Least Cost)	2%	10%	17%	30%	58%
% Difference (80% Clean – Least Cost)	2%	10%	17%	19%	22%

Table 7: Revenue Requirement ($M) - Ascend Assumptions

	2025	2030	2035	2040	2050
100% Clean	2,714	3,472	3,969	4,738	7,952
80% Clean	2,714	3,472	3,969	4,410	6,193
Least Cost	2,613	3,164	3,436	3,789	5,545
Difference (100% Clean – Least Cost)	100	308	533	949	2,407
Difference (80% Clean – Least Cost)	100	308	533	621	648
% Difference (100% Clean – Least Cost)	4%	10%	16%	25%	43%
% Difference (80% Clean – Least Cost)	4%	10%	16%	16%	12%

Table 8: Revenue Requirement Net Present Value[5] ($M) for 2021 - 2050

	APS Assumptions	Ascend Assumptions
100% Clean	46,717	48,401
80% Clean	44,390	46,092
Least Cost	40,231	42,157
Difference (100% Clean – Least Cost)	6,486	6,244
Difference (80% Clean – Least Cost)	4,158	3,935
% Difference (100% Clean – Least Cost)	16%	15%
% Difference (80% Clean – Least Cost)	10%	9%

[5] Assumes 7% annual discount rate

Table 9: Average Rate Impacts ($/kWh) - Utility Assumptions

	2025	2030	2035	2040	2050
100% Clean	0.083	0.088	0.091	0.094	0.136
80% Clean	0.083	0.088	0.091	0.086	0.105
Least Cost	0.079	0.077	0.073	0.067	0.076
Difference (100% Clean – Least Cost)	0.0036	0.0109	0.0179	0.0274	0.0597
Difference (80% Clean – Least Cost)	0.0036	0.0109	0.0179	0.0191	0.0285
% Difference (100% Clean – Least Cost)	4%	14%	24%	41%	78%
% Difference (80% Clean – Least Cost)	4%	14%	24%	29%	37%

Table 10: Average Rate Impacts ($/kWh) - Ascend Assumptions

	2025	2030	2035	2040	2050
100% Clean	0.079	0.090	0.094	0.104	0.147
80% Clean	0.079	0.090	0.094	0.097	0.115
Least Cost	0.074	0.078	0.077	0.077	0.091
Difference (100% Clean – Least Cost)	0.0044	0.0111	0.0175	0.0273	0.0563
Difference (80% Clean – Least Cost)	0.0044	0.0111	0.0175	0.0202	0.0237
% Difference (100% Clean – Least Cost)	6%	14%	23%	36%	62%
% Difference (80% Clean – Least Cost)	6%	14%	23%	26%	26%

Table 11: Average Monthly Residential Bill[6] Impacts ($) - Utility Assumptions

	2025	2030	2035	2040	2050
100% Clean	90.73	94.56	95.66	96.78	134.14
80% Clean	90.73	94.56	95.66	88.33	103.36
Least Cost	88.53	86.23	81.68	74.54	84.96
Difference (100% Clean – Least Cost)	2.20	8.33	13.98	22.24	49.19
Difference (80% Clean – Least Cost)	2.20	8.33	13.99	13.79	18.41
% Difference (100% Clean – Least Cost)	2%	10%	17%	30%	58%
% Difference (80% Clean – Least Cost)	2%	10%	17%	19%	22%

[6] *Uses APS' forecast for monthly consumption per customer*

Table 12: Average Monthly Residential Bill Impacts[7] ($) - Ascend Assumptions

	2025	2030	2035	2040	2050
100% Clean	85.93	96.04	99.09	106.78	145.29
80% Clean	85.93	96.04	99.09	99.39	113.15
Least Cost	82.75	87.52	85.78	85.39	101.31
Difference (100% Clean – Least Cost)	3.18	8.52	13.32	21.38	43.98
Difference (80% Clean – Least Cost)	3.18	8.52	13.32	14.00	11.84
% Difference (100% Clean – Least Cost)	4%	10%	16%	25%	43%
% Difference (80% Clean – Least Cost)	4%	10%	16%	16%	12%

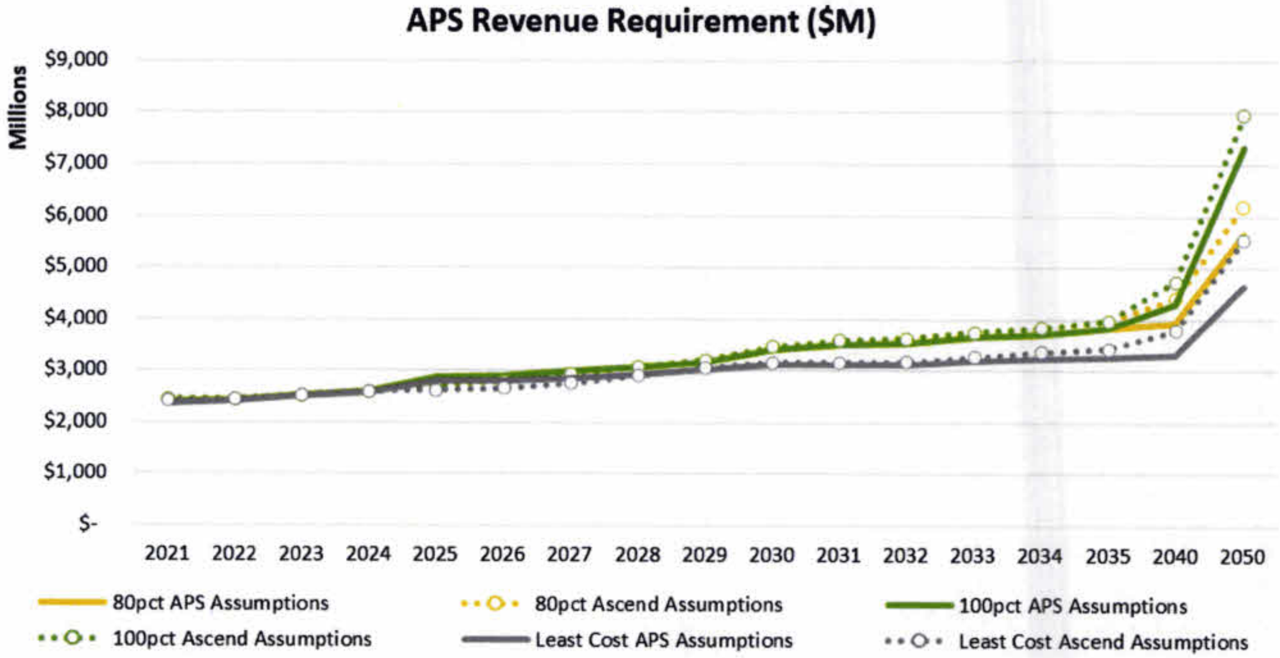


Figure 26: APS revenue requirement (including transmission expansions)

Revenue requirements are very similar in the first 15 years for both Ascend and APS assumptions. A deviation is observed in years 2040 and 2050 driven by minor differences in the assumptions. APS ELCC assumptions are reasonably aligned to Ascend's forecast, both declining over the 30 years, however Ascend's ELCC drop is slightly more aggressive resulting in additional required capacity to meet peak demand and thus slightly higher capital costs.

[7] *Uses APS' forecast for monthly consumption per customer*

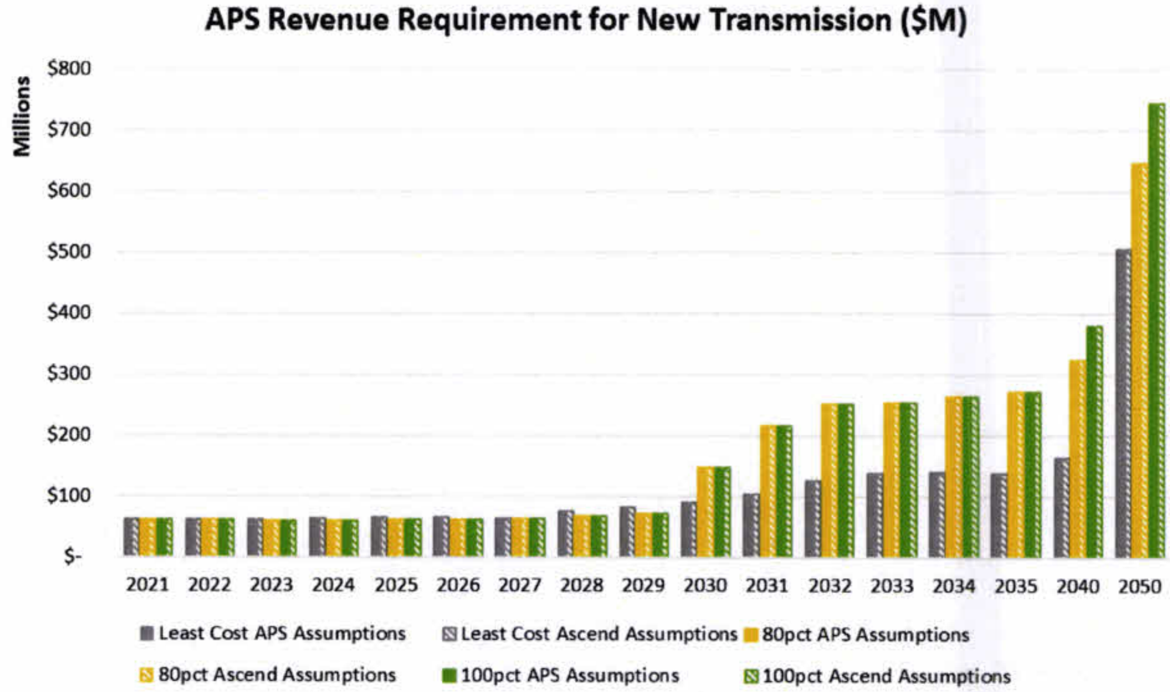


Figure 27: APS revenue requirement for new transmission

Cost of new transmission lines is one component of the overall revenue requirement. Transmission requirements are very similar across all scenarios until 2030, after which the 80% and 100% cases require significantly higher revenue requirements.

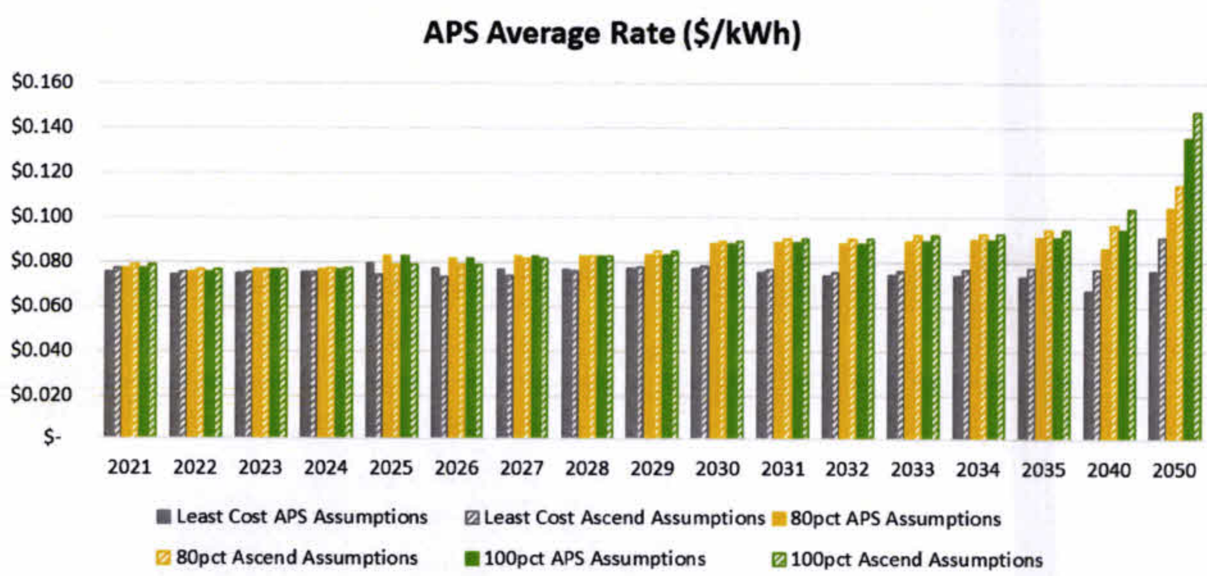


Figure 28: APS average electricity rate

The difference in average rates in the first 10 years is minimal across all scenarios and assumptions. Post 2030 the gap widens, and the "Least Cost" remains consistently cheaper than the 80% and 100% cases until 2050

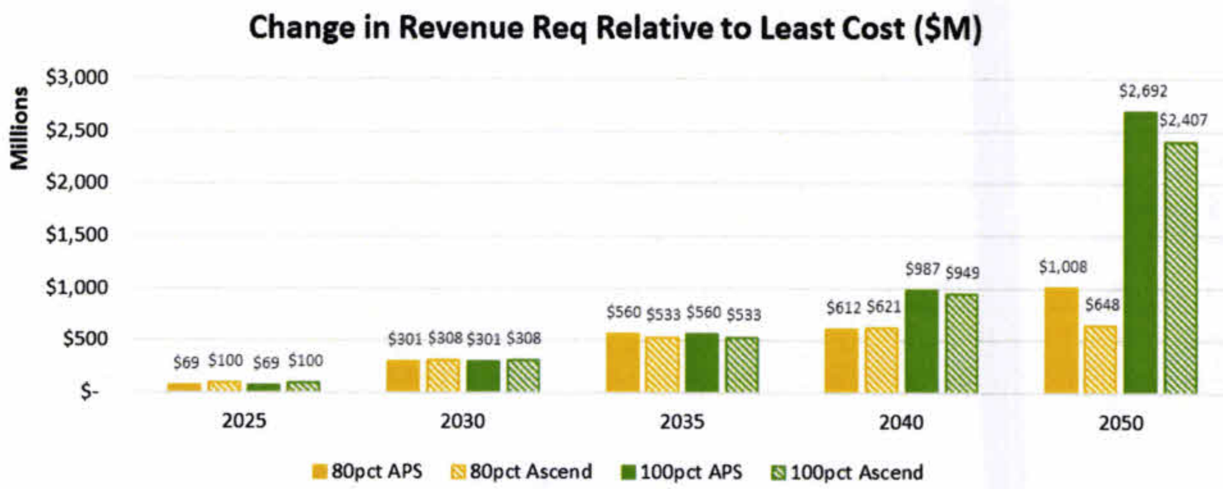


Figure 29: APS change in revenue requirement relative to the least cost scenario

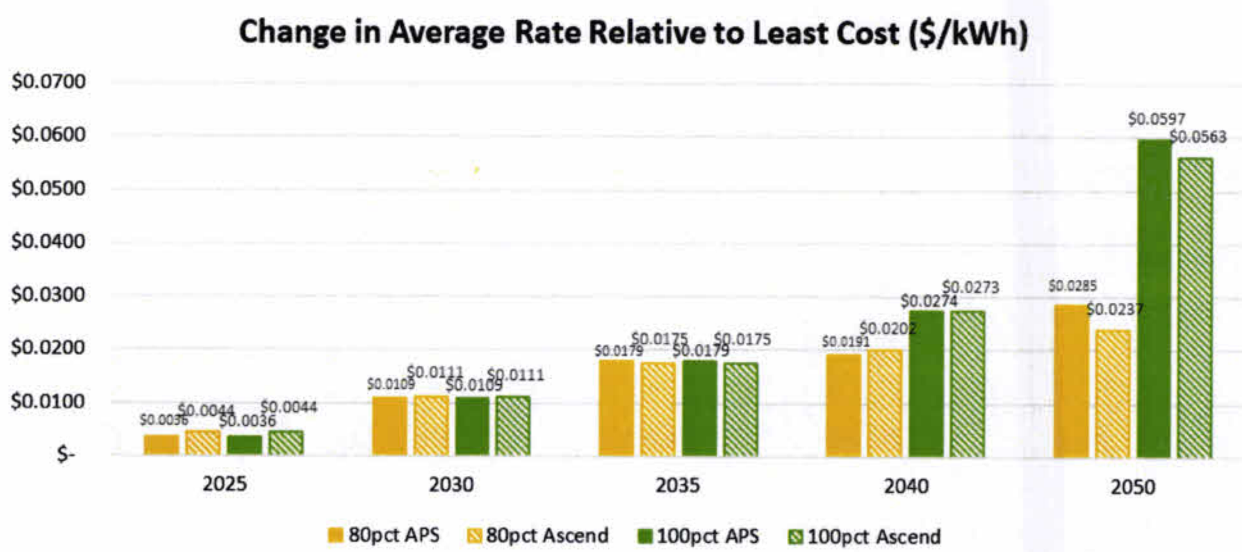


Figure 30: APS change in average electricity rate relative to the least cost scenario

Looking at the incremental difference until 2040 relative to the "Least Cost" case, the energy rules seem to have a low impact on the average rate and revenue requirement. The 100% case in 2050 has double the incremental cost than the 80% case.

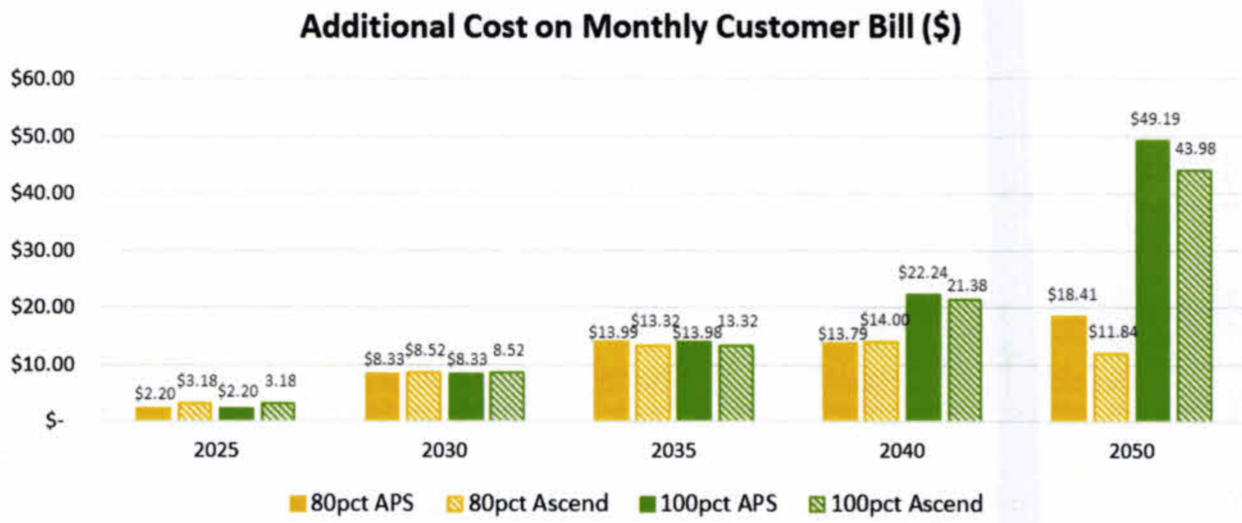


Figure 31: APS monthly additional cost on electricity bill as a result of adopting the energy rules

Calculating the customer bill based on a forecasted monthly consumption, the 80% carbon free target results in an additional cost of $12 to $18 in 2050 dollars compared to $44 to $49 in the 100% case.

Overall, the results show that the Energy Rules will have modest cost increases for the 80% target and significantly higher increases for the 100% target. As mentioned earlier these outputs rely on assumptions for future technology costs and market prices that are extremely uncertain when projecting out to 2050. Finally, the path to 80% or 100% will rely on significant investments in renewables and energy storage. There may also be a fair amount of investment in renewable fuels such as hydrogen which has yet to be commercially deployed. The Energy Rules will propel APS and others to keep on the path towards a clean energy future while they monitor developments and innovations in the energy sector to determine the best path forward.

4.2 TEP

4.2.1 APPROACH

To analyze the cost associated with the energy rules Ascend and TEP hand designed portfolios that had 80% and 100% reductions in carbon emission by 2050 as well as a least cost portfolio. The 80% and 100% reductions portfolios were setup to comply with the draft Energy Rules for both 80% and 100% reductions in carbon emissions by 2050. After creating the portfolios under both Ascend and TEP's assumptions on ELCC and market prices, the TEP resource planning staff used their production cost model to estimate the costs of each portfolio. The outputs from the production cost modeling were used to assess the cost of the Energy Rules and their impact on customer rates.

4.2.2 INPUTS AND ASSUMPTIONS

Demand Side

For both TEP, the IRP served as the foundation for analysis, but a variety of other data sources were necessary to supplement it, including the following:

- TEP 2021 DSM Plan
- TEP Load Forecast Update
- TEP Forecast Documentation
- TEP Staff Responses to Data Requests

For cases where the necessary data elements have multiple values or insufficient detail, the above sources were often bolstered by additional research and professional judgement. The remainder of this section describes the data and approaches used to develop the necessary series for this IRP review.

TEP Base Forecast: In the available data, the energy forecast for TEP increases from 8,970 GWh in 2020 to 11,721 GWh in 2035, with an average annual growth rate of 1.8%. The base forecast for peak demand shows growth from 2,589 MW in 2020 to 2,931 MW in 2035. The average annual growth rate of 0.8% is substantially lower than the energy forecast.

TEP Electrification: The electrification data for TEP consisted of a forecast of the annual energy associated with EVs, beginning with a total of 7 GWh and increasing to 786 GWh in 2035. Given the low starting point and anticipated adoption, the annual rate of this growth in these data varied greatly, starting at more than 200% per year and declining annually. The extrapolation of these data to 2050 was more challenging given the lack of detail in the data and the high uncertainty regarding EV adoption. The data provided by TEP show that by 2035, around 45% of TEPs residential customers will have an electric vehicle (assuming an annual consumption of 4,000 kWh). The application of linear extrapolation to these data would result in 65% of customers having EVs in 2050, which was deemed too low based on limited available forecasts. For TEP, the extrapolation of the starting by developing a 2050 estimate of total EV consumption based on an assumption that 80% of customers would have one EV and then filling in the series from 2035 to 2050 to represent a more typical adoption curve, with a declining rate of growth towards the end of the forecast horizon.

The peak demand for EVs assumed that most charging will occur off peak, so coincident load factor of 0.2 was applied to the energy data. Note that there was no data regarding other components of electrification and no difference in the data for the energy rules and least cost scenarios.

TEP Energy Efficiency: TEP's IRP did not include the required forecast of both energy efficiency energy and peak demand savings, so these series were derived from several sources. For the series representing savings compliant with the energy rules, the data came from a response to a data request for this IRP review. This data request included the incremental energy efficiency added annually through 2050, ***(Begin Confidential Information)*** *[Redacted due to confidentiality]* ***(End Confidential Information)***. Because these data extended to 2050, it was not necessary to extend these series to meet the requirements. The data request also included information on the 8,760 hourly shape of the resource, which was used to convert the annual energy savings into peak demand impacts. Using the average savings from July weekdays from 4:00 PM to 7:00 PM, the energy savings translate into peak demand savings of ***(Begin Confidential Information)*** *[Redacted due to confidentiality]* ***(End Confidential Information)***.

The least cost scenario for energy efficiency relied on data in the IRP, which includes a series of annual MW of peak demand savings associated with energy savings. These data showed peak demand savings of 1 MW in 2020 increasing to 112 MW in 2035. Using linear extrapolation, this series was extended to 214 MW in 2050. Using the same relationship between energy and demand in the energy rules scenario, this series was converted to energy savings of ***(Begin Confidential Information)*** *[Redacted due to confidentiality]* ***(End Confidential Information)***.

TEP Demand Response: Both historically and in its forecast, TEP has only a small presence of peak demand savings from demand response. For both energy rules and least cost scenarios, the demand response series is based on the 41 MW of savings from the 2020 DSM plan – representing about 1.6% of the system peak – increasing to 57 MW in 2050. With no information in the IRP or other data sources to suggest that TEP intends to expand its DR capabilities, this is based on the same rate of growth as the base peak demand. These series were used for both energy rules and low-cost scenarios.

TEP Distributed Generation: For both energy rules and least cost scenarios, distributed generation series are based on the IRP's MW savings from 2020 to 2035, which translate to incremental peak demand savings of 3 MW in 2020 increasing to 57 MW in 2050. Using the assumption that most of these savings are due to solar, they translate into 5.3 GWh of energy savings in 2020 increasing to 123 GWh in 2050. Again, these series were used for both energy rules and least cost scenarios.

Supply Side

The Ascend and TEP assumptions on ELCC assumptions are very different. Ascend assumes that the ELCC of renewable resources and storage will decline over the next 30 years whereas TEP keeps their capacity value constant. The divergence in ELCC assumptions between Ascend and TEP result in the portfolios designed by Ascend having significantly more nameplate capacity.

Another source of difference between Ascend and TEP are the market price assumptions. As discussed in Section 3.4.2, Ascend forecasts market prices to remain flat in nominal terms over the next 30 year whereas TEP forecasts market prices to steadily increase.

The table below shows the portfolio capacity by resource type. The Energy Rules portfolios rely much more on renewables and energy storage while the least cost portfolio adds a lot of natural gas capacity.

Table 13: TEP Portfolio Capacity by Resource Type – TEP Assumptions

	TEP Least Cost			TEP Energy Rules 80%			TEP Energy Rules 100%		
	2030	2040	2050	2030	2040	2050	2030	2040	2050
Natural Gas	1,679	1,419	1,419	1,679	1,419	1,419	1,679	1,757	-
Coal	516	-	-	516	-	-	516	-	-
Nuclear	-	-	-	-	-	-	-	-	-
Solar	548	1,969	1,969	548	2,669	3,169	548	2,669	3,169
Wind	625	1,075	1,075	625	1,625	1,625	625	1,625	1,625
Geothermal	-	-	-	-	-	-	-	-	-
Biomass	-	-	-	-	-	-	-	-	-
Storage (4 hours)	595	1,445	1,445	595	1,445	1,445	595	1,445	1,445
Storage (8 hours)	-	-	-	-	550	800	-	500	800
Storage (12 hours)	-	-	-	-	-	-	-	-	-
Microgrid	-	-	-	-	-	-	-	-	-
Market Purchases	-	-	-	-	-	-	-	-	-
Renewable Fuels	-	-	-	-	-	-	-	-	1,757

Table 14: TEP Portfolio Capacity by Resource Type – Ascend Assumptions

	Ascend Least Cost			Ascend Energy Rules 80%			Ascend Energy Rules 100%		
	2030	2040	2050	2030	2040	2050	2030	2040	2050
Natural Gas	2,329	3,048	2,725	1,679	1,623	1,972	1,679	1,373	-
Coal	516	-	-	516	-	-	516	-	-
Nuclear	-	-	-	-	-	-	-	-	-
Solar	548	2,169	1,919	548	1,169	3,169	458	2,169	4,169
Wind	625	875	1,419	625	1,875	2,875	625	1,875	2,875
Geothermal	-	-	-	-	-	-	-	-	-
Biomass	-	-	-	-	-	-	-	-	-
Storage (4 hours)	595	1,530	2,530	630	2,030	3,030	630	2,030	3,030
Storage (8 hours)	-	-	-	255	1,000	2,000	255	1,000	2,000
Storage (12 hours)	-	-	-	-	-	-	-	250	500
Microgrid	-	-	-	-	-	-	-	-	-
Market Purchases	-	-	-	-	-	-	-	-	-
Renewable Fuels	-	-	-	-	-	-	-	-	-

4.2.3 RESULTS

The results of the analysis for TEP are shown in the following tables:

Table 15: Revenue Requirements ($M) – Utility Assumptions

	2025	2030	2035	2040	2050
100% Clean	1,226	1,410	1,540	1,713	2,067
80% Clean	1,224	1,409	1,540	1,687	1,894
Least Cost	1,224	1,409	1,540	1,669	1,874
Difference (100% Clean – Least Cost)	2	1	1	44	193
Difference (80% Clean – Least Cost)	0	0	0	18	19
% Difference (100% Clean – Least Cost)	0%	0%	0%	3%	10%
% Difference (80% Clean – Least Cost)	0%	0%	0%	1%	1%

Table 16: Revenue Requirements ($M) – Ascend Assumptions

	2025	2030	2035	2040	2050
100% Clean	1,223	1,484	1,650	2,033	3,085
80% Clean	1,223	1,484	1,650	1,978	2,864
Least Cost	1,223	1,424	1,518	1,779	2,365
Difference (100% Clean – Least Cost)	0	60	132	254	720
Difference (80% Clean – Least Cost)	0	60	132	199	499
% Difference (100% Clean – Least Cost)	0%	4%	9%	14%	30%
% Difference (80% Clean – Least Cost)	0%	4%	9%	11%	21%

Table 17: Revenue Requirement Net Present Value[8] ($M) for 2021 - 2050

	TEP Assumptions	Ascend Assumptions
100% Clean	19,196	21,091
80% Clean	18,962	20,775
Least Cost	18,910	19,645
Difference (100% Clean – Least Cost)	286	1,446
Difference (80% Clean – Least Cost)	52	1,130
% Difference (100% Clean – Least Cost)	2%	7%
% Difference (80% Clean – Least Cost)	0%	6%

[8] *Assumes 7% annual discount rate*

Table 18: Average Rate Impacts ($/kWh) – Utility Assumptions

	2025	2030	2035	2040	2050
100% Clean	0.136	0.141	0.145	0.152	0.167
80% Clean	0.135	0.141	0.145	0.150	0.153
Least Cost	0.135	0.141	0.145	0.148	0.152
Difference (100% Clean – Least Cost)	0.0002	0.0001	0.0001	0.0039	0.0156
Difference (80% Clean – Least Cost)	0.0000	0.0000	0.0000	0.0016	0.0016
% Difference (100% Clean – Least Cost)	0%	0%	0%	3%	10%
% Difference (80% Clean – Least Cost)	0%	0%	0%	1%	1%

Table 19: Average Rate Impacts ($/kWh) – Ascend Assumptions

	2025	2030	2035	2040	2050
100% Clean	0.135	0.148	0.155	0.181	0.249
80% Clean	0.135	0.148	0.155	0.176	0.231
Least Cost	0.135	0.142	0.143	0.158	0.191
Difference (100% Clean – Least Cost)	0.0000	0.0060	0.0124	0.0226	0.0582
Difference (80% Clean – Least Cost)	0.0000	0.0060	0.0124	0.0177	0.0403
% Difference (100% Clean – Least Cost)	0%	4%	9%	14%	30%
% Difference (80% Clean – Least Cost)	0%	4%	9%	11%	21%

Table 20: Average Monthly Residential Bill Impacts[9] ($) – Utility Assumptions

	2025	2030	2035	2040	2050
100% Clean	135.64	140.97	145.09	152.31	167.14
80% Clean	135.42	140.86	145.02	149.99	153.09
Least Cost	135.43	140.86	145.02	148.41	151.53
Difference (100% Clean – Least Cost)	0.21	0.11	0.07	3.90	15.61
Difference (80% Clean – Least Cost)	0.00	0.00	0.00	1.58	1.56
% Difference (100% Clean – Least Cost)	0%	0%	0%	3%	10%
% Difference (80% Clean – Least Cost)	0%	0%	0%	1%	1%

[9] Assumes *1,000 kWh monthly consumption per customer*

Table 21: Average Monthly Residential Bill Impacts[10] ($) – Ascend Assumptions

	2025	2030	2035	2040	2050
100% Clean	135.32	148.40	155.40	180.73	249.38
80% Clean	135.29	148.38	155.40	175.82	231.49
Least Cost	135.29	142.41	143.00	158.16	191.15
Difference (100% Clean – Least Cost)	0.03	5.99	12.40	22.57	58.23
Difference (80% Clean – Least Cost)	0	5.97	12.40	17.66	40.33
% Difference (100% Clean – Least Cost)	0%	4%	9%	14%	30%
% Difference (80% Clean – Least Cost)	0%	4%	9%	11%	21%

Note that the revenue requirements and average rates should not be compared between APS and TEP. The revenue requirement for TEP is all-in and includes the costs associated with distribution systems while APS includes only generation and transmission costs. However, distribution costs are considered the same across the different cases and thus the interest lies in the incremental cost relative to the "least cost" scenario. Also, the customer usage assumptions are slightly different between the two utilities causing the average rates to have different base lines.

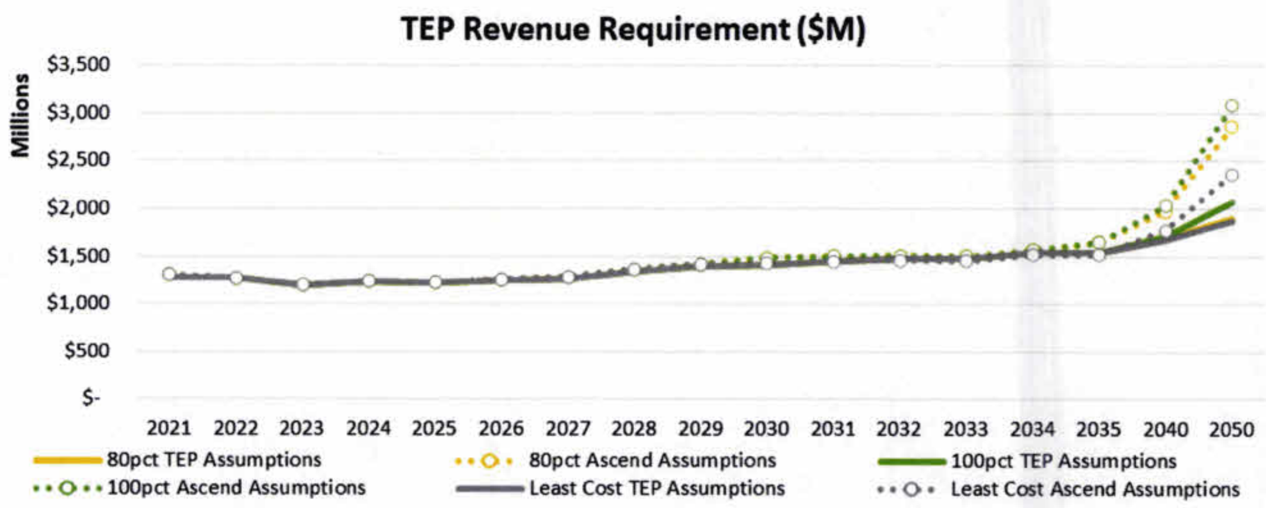


Figure 32: TEP revenue requirement (including transmission expansions)

[10] Assumes *1,000 kWh monthly consumption per customer*

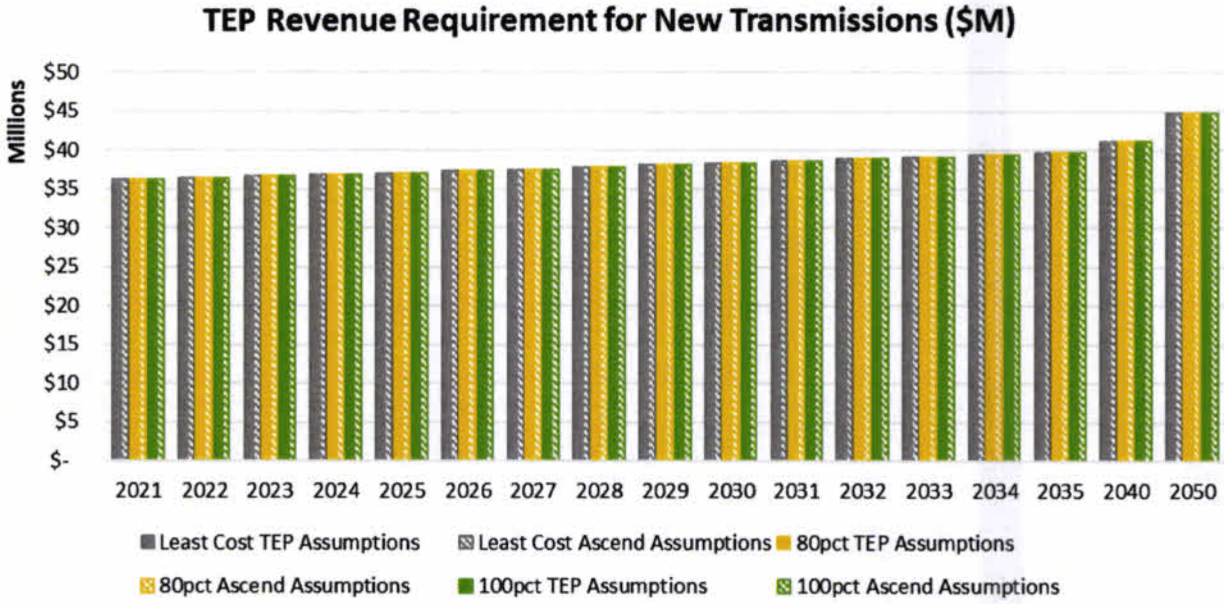


Figure 33: TEP revenue requirement for new transmission expansions

Revenue requirements are similar in the first 15 years for both Ascend and TEP assumptions. However, a strong deviation occurs in years 2040 and 2050 due to major differences in the assumptions. The revenue requirement and therefore the rate increases are mainly driven by the capital costs of new resources. The lower ELCC assumption on renewable resources in the Ascend cases results in portfolios with more nameplate capacity which in turn results in greater revenue requirements. Cost of new transmission lines is included in the revenue requirement and is assumed to be the same across all six cases.

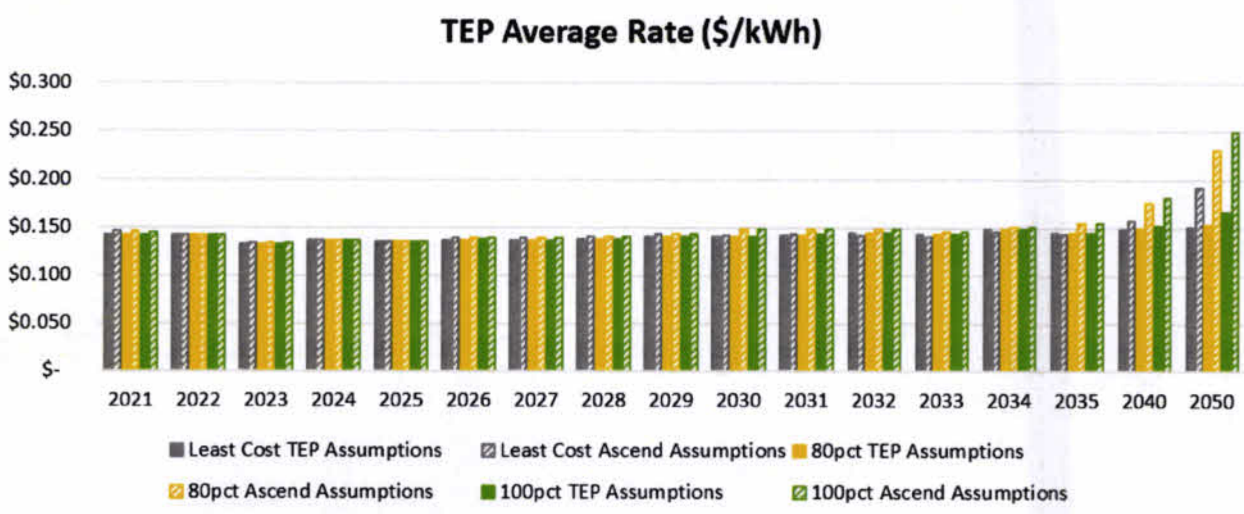


Figure 34: TEP average electricity rate

The "Least Cost" and 80% cases have relatively similar average rates across the 30 years. Post 2040, the 100% case becomes more expensive than its counterparts with the difference more readily apparent using Ascend assumptions.

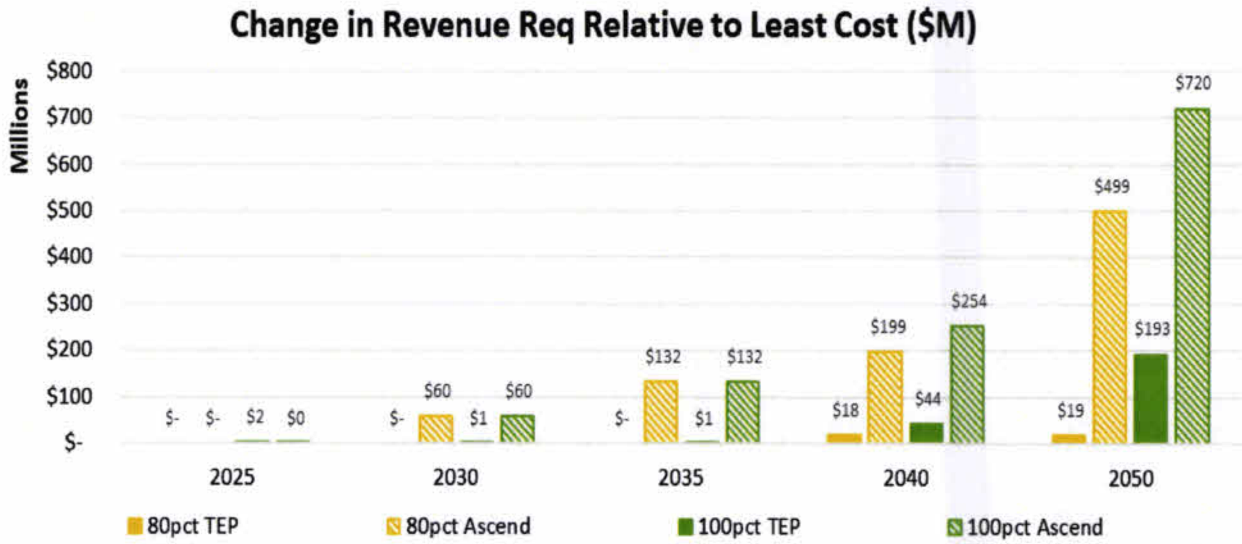


Figure 35: TEP change in revenue requirement relative to the least cost scenario

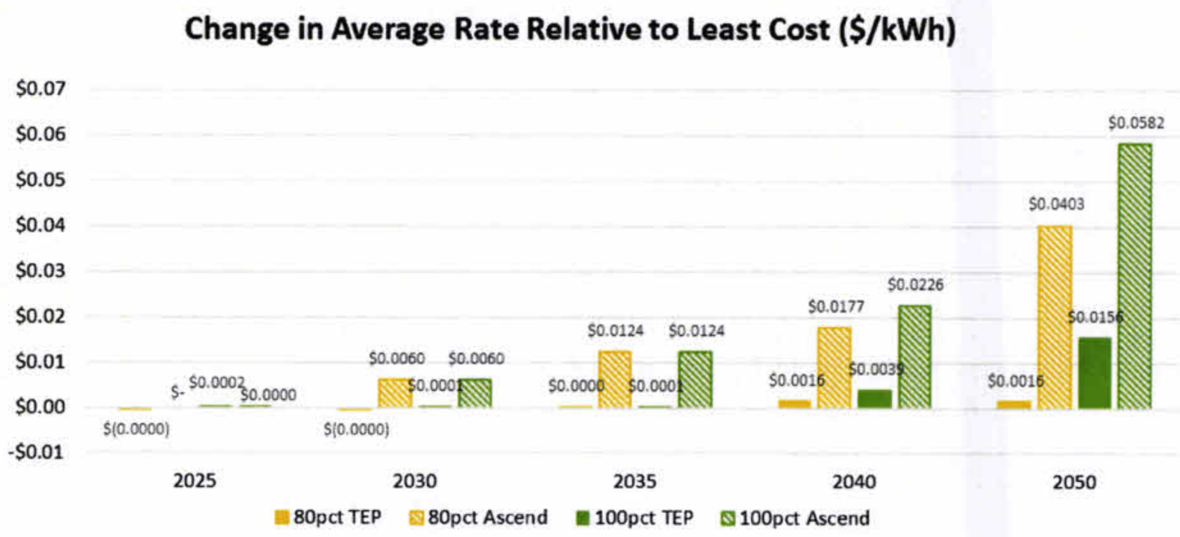


Figure 36: TEP change in average electricity rate relative to the least cost case

Looking at the incremental difference relative to the "Least Cost" case, both energy rules scenarios seem to have a moderate impact on the average rate and revenue requirement.

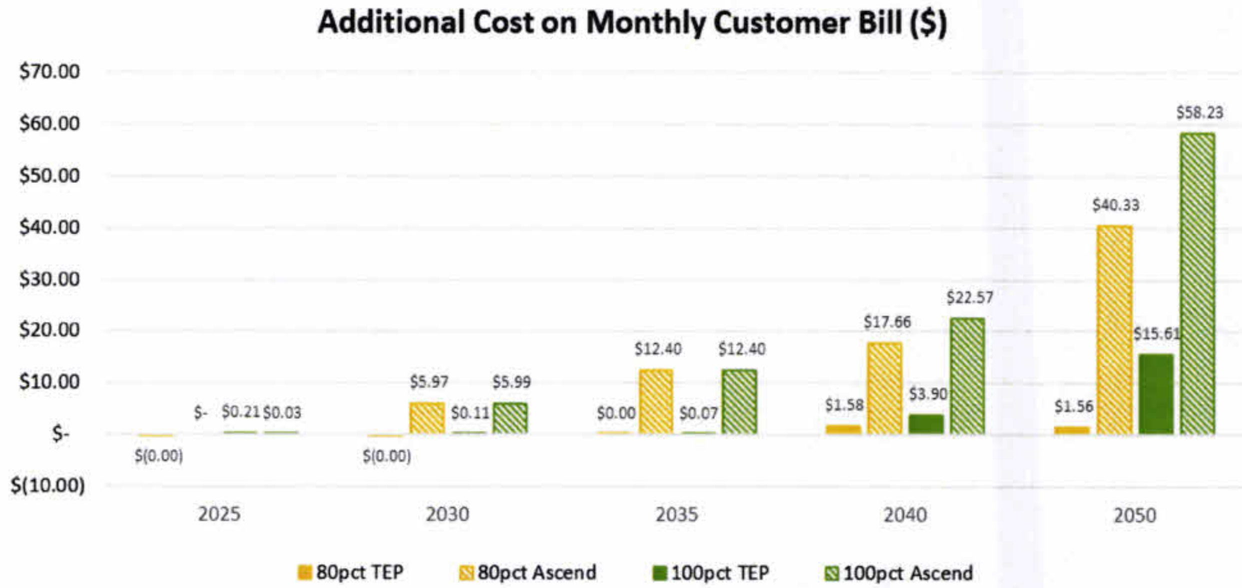


Figure 37: TEP monthly additional cost on electricity bill as a result of adopting the energy rules

The differences in assumptions used by TEP and Ascend provide a range of costs for the Energy Rules. The change in customer rates relative to the least cost portfolios is minimal before 2035. The larger carbon reductions needed after 2035 to meet 80% or 100% reductions drive the average rates up by $0.058/kWh in the Ascend assumptions case by 2050 with the TEP assumptions yielding a smaller rate increase.

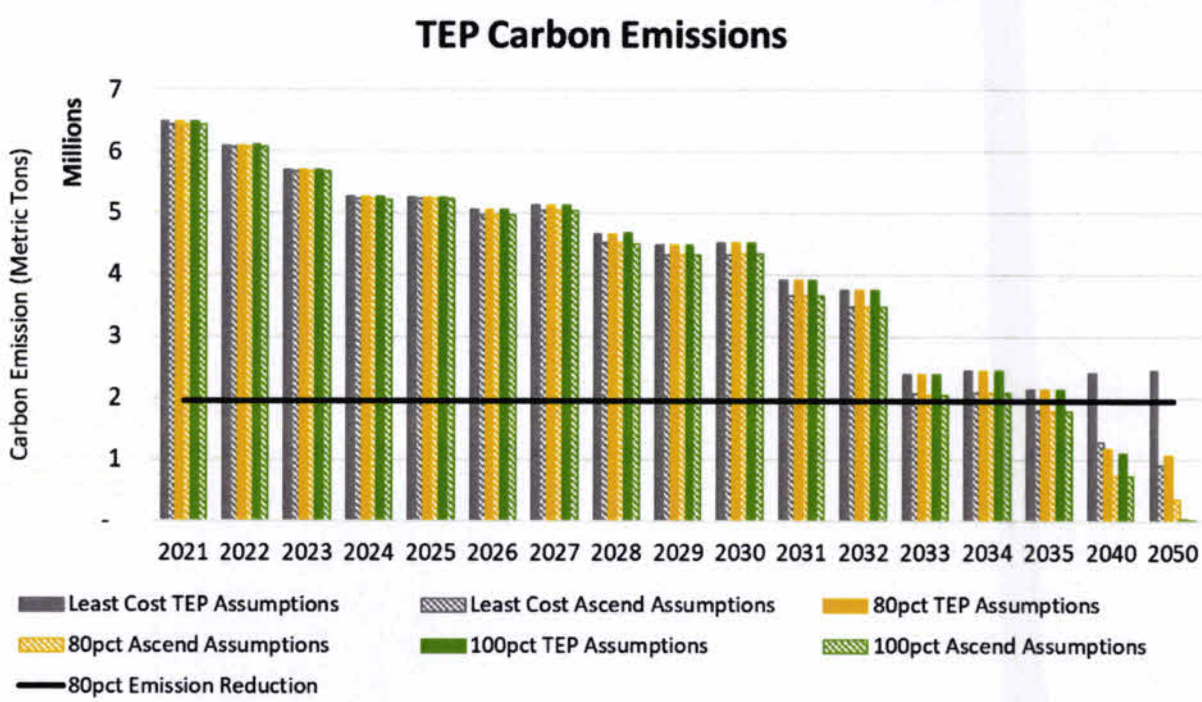


Figure 38: TEP carbon emissions

The retirement of all coal generation by 2032 drives the majority of the carbon reductions through the IRP period. After 2035, the carbon emissions reductions diverge based on the constraints for each portfolio. The energy rules portfolios all reduce emissions by at least 80% in 2050.

The Energy Rules have a small/moderate nominal cost to reach 80% carbon reductions while achieving a 100% by 2050 has a larger cost. Given the influence that capital costs have on the overall cost of the energy rules, the costs of new resources in the 2040s will play an outsized role in the true cost of the Energy Rules. The path to both 80% and 100% reductions in carbon emission rely heavily on renewables and storage. The portfolios that were analyzed for TEP all include the resources necessary to continue decarbonizing the TEP system.

4.3 STUDY LIMITATIONS AND RECOMMENDATIONS FOR FURTHER ANALYSIS

As with any very long-range study, results in the distant future must be taken somewhat with a grain of salt. We have little information as to what technologies will be available or how exactly the power system will evolve. We believe these results are directionally consistent with an emerging consensus[11] that decarbonizing the power sector until at least 80% - 90% clean energy is achievable and cost-effective with today's technology over a timespan covering the next two decades.

Some limitations include:

- The studies only compare three discrete scenarios, none of which were optimized. A more thorough study would leverage capacity expansion algorithms as well as discrete sensitivities to test key assumptions.
- This study was not paired with loss of load probability analysis. We cannot say with confidence that these portfolios are reliable without conducting an independent reliability analysis.
- This study was performed deterministically, meaning we do not analytically capture meaningful uncertainty driven by weather as a fundamental driver of load, renewable output, forced outages, and gas and power price dynamics. A deterministic result only shows a single view of the world versus a distribution of possible outcomes.
- Study is completed with perfect foresight (i.e. model "sees" all prices and optimizes dispatch perfectly) at the hourly level (as opposed to 5-minute intervals), which fundamentally undervalues flexible resources such as batteries in the context of participation in the Western Energy Imbalance Market (EIM).

Analytical studies such as this one, provide important insights into the mechanics of complex systems including how changes in assumptions about future uncertainties would impact the outcomes. The following table highlights key assumptions and how results would be affected if they were more or less than we believe today.

[11] For example, see NREL study on reaching 100% clean electricity https://www.nrel.gov/news/program/2021/the-challenge-of-the-last-few-percent-quantifying-the-costs-and-emissions-benefits-of-100-renewables.html

Table 22: Understanding the Impacts of Key Uncertainties

Assumption	What would cause costs to be less than expected?	What would cause costs to be more than expected?
Effective load carrying capability (ELCC)	ELCC of wind, solar, and batteries are more than we expect, potentially as a function of portfolio effects and geographic diversity.	ELCC of wind, solar, and batteries are less than we expect, potentially as a function of strong correlation in weather regimes on renewable output.
Technology types and costs	If innovation makes storage dramatically more cost-effective than we expect costs of decarbonization would decrease.	If future technologies do not decline as we expect, then costs to decarbonize would be higher than shown here.
Climate change	Climate impacts are more moderate than we expect, meaning less need to build peaking capacity for heat storms.	Climate impacts are worse than we expect, therefore additional capacity is needed to maintain reliability during more frequent and longer heat storms.
Market structure	If LSEs join a regional RTO, the cost of decarbonization due to better coordination of resources across the West.	Not applicable.
Transmission	Federal spending and permitting reforms support additional transmission that unlocks more low-cost renewable energy. Higher adoption and targeted deployment of distribution sited storage and distributed energy resources reduces the need for transmission spending.	No federal spending or permitting reform. Low adoption/sub-optimal deployment of distributed energy resources.

Should the ACC feel more analysis would be beneficial to support regulatory policy making, Ascend makes the following recommendations:

1. Commission a study using an independent analytical firm (and/or national lab, ASU, etc.) to model pathways to 100% clean energy by 2050.
2. Make sure to hire an analyst that uses best-in-class "HD PCMs." There are several that have been developed by various modeling firms.
3. Include other sectors in the analysis, such as transportation and building electrification.
4. Investigate both supply and demand-side solutions.
5. Utilize capacity expansion and scenario design.
6. Include a stakeholder engagement process.
7. Make sure to include reliability analysis, resiliency, and climate impacts.
8. Allot a sufficient amount of time and resources to make the analysis robust and meaningful. Nine months to one year is typical.

5 Appendix

5.1 APS LOAD AND RESOURCE TABLES

Below are the load and resource tables developed by APS and the Ascend team for assessing the costs of the proposed energy rules.

Load and Resource Table for Least Cost Portfolio

System Peak Demand	2020	2025	2030	2035	2040	2050
Base Peak Demand (MW)	7,468	8,639	9,950	11,227	12,599	15,890
Electrification - EV & Building (MW)	2	8	23	44	73	128
Energy Efficiency (MW)	(105)	(486)	(890)	(1,207)	(1,553)	(1,914)
Distributed Generation (MW)	(4)	(39)	(132)	(225)	(283)	(286)
Demand Response (MW)	(21)	(137)	(224)	(337)	(399)	(574)
Net System Peak (MW)	**7,340**	**7,986**	**8,726**	**9,503**	**10,437**	**13,244**
Planning Reserve Margin (%)	15%	15%	15%	15%	15%	15%
Reserve Requirements (MW)	1,026	1,224	1,362	1,510	1,668	2,116
Total Firm Load Obligation (MW)	**8,366**	**9,210**	**10,088**	**11,012**	**12,105**	**15,360**

Supply Resources (Existing)	2020	2025	2030	2035	2040	2050
Existing Resources Capacity (MW)						
NGCC	2,995	3,489	1,891	1,891	1,891	1,891
NGCT	1,545	1,545	1,545	1,545	1,545	1,545
Coal	1,357	970	970	-	-	-
Nuclear	1,146	1,146	1,146	1,146	1,146	1,146
Solar	532	525	517	510	499	195
Wind	284	284	197	197	-	-
Geothermal	10	10	-	-	-	-

Biomass/Biogas	17	3	3	-	-	-
Storage (4 hours)	2	2	2	2	-	-
Microgrid	32	32	32	32	32	32
Market Purchases	685	160	160	160	160	160
Contribution to Peak - ELCC Adjusted (MW)						
Thermal (Gas, Coal, Nuclear)	7,043	7,150	5,552	4,582	4,582	4,582
Renewables (Solar, Wind, Geothermal, Biomass)	489	468	401	363	297	10
Energy Storage	2	1	1	1	-	-
Other (Microgrid, Market Purchases)	717	192	192	192	192	192
Total Contribution to Peak from Existing (MW)	**8,251**	**7,812**	**6,146**	**5,138**	**5,071**	**4,784**

Supply Resources (Future)	**2020**	**2025**	**2030**	**2035**	**2040**	**2050**
Future Resources Capacity (MW)						
NGCC	-	-	1,677	2,219	2,761	3,303
NGCT (frame)	-	724	1,810	2,896	2,896	5,068
Solar	-	200	200	500	1,050	2,450
Wind	-	362	450	450	600	2,250
Biomass/Biogas	-	-	-	-	-	-
Renewable Fuels	-	-	-	-	-	-
Storage (4 hours)	-	550	550	850	1,400	1,850
Storage (8 hours)	-	-	-	-	-	-
Storage (12 hours)	-	-	-	-	-	-
Microgrid	-	206	231	281	281	281
Market Purchases	150	-	-	-	-	-
Contribution to Peak - ELCC Adjusted (MW)						
Thermal (Gas, Nuclear)	-	724	3,487	5,115	5,657	8,371
Renewables (Solar, Wind, Geothermal, Biomass, Fuels)	-	159	174	206	260	782
Energy Storage	-	371	390	560	889	1,153
Other (Microgrid, Market Purchases)	150	206	231	281	281	281
Total Contribution to Peak from Future (MW)	**150**	**1,460**	**4,282**	**6,161**	**7,086**	**10,587**

Total Planning Capacity	2020	2025	2030	2035	2040	2050
Total Capacity (MW)	8,401	9,272	10,429	11,299	12,157	15,371
Capacity Position (MW)	35	62	340	287	52	11

Load and Resource Table for Energy Rules 80% Portfolio

System Peak Demand	2020	2025	2030	2035	2040	2050
Base Peak Demand (MW)	7,468	8,639	9,950	11,227	12,599	15,890
Electrification - EV & Building (MW)	2	8	23	44	73	128
Energy Efficiency (MW)	(105)	(754)	(1,479)	(2,155)	(2,832)	(4,111)
Distributed Generation (MW)	(4)	(40)	(133)	(206)	(200)	(130)
Demand Response (MW)	(21)	(137)	(224)	(337)	(399)	(574)
Net System Peak (MW)	**7,340**	**7,716**	**8,136**	**8,573**	**9,241**	**11,203**
Planning Reserve Margin (%)	15%	15%	15%	15%	15%	15%
Reserve Requirements (MW)	1,026	1,184	1,274	1,367	1,476	1,786
Total Firm Load Obligation (MW)	**8,366**	**8,900**	**9,410**	**9,940**	**10,717**	**12,989**

Supply Resources (Existing)	2020	2025	2030	2035	2040	2050
Existing Resources Capacity (MW)						
NGCC	2,991	3,489	1,891	1,891	1,891	1,891
NGCT	1,545	1,545	1,545	1,545	1,545	1,545
Coal	1,357	970	970	-	-	-
Nuclear	1,146	1,146	1,146	1,146	1,146	1,146
Solar	532	525	517	510	499	195
Wind	284	284	197	197	-	-
Geothermal	10	10	-	-	-	-
Biomass/Biogas	17	3	3	-	-	-
Storage (4 hours)	2	2	2	2	-	-
Microgrid	32	32	32	32	32	32

Market Purchases	685	160	160	160	160	160
Contribution to Peak - ELCC Adjusted (MW)						
Thermal (Gas, Coal, Nuclear)	7,039	7,150	5,552	4,582	4,582	4,582
Renewables (Solar, Wind, Geothermal, Biomass)	485	464	374	324	259	5
Energy Storage	2	1	1	1	-	-
Other (Microgrid, Market Purchases)	717	192	192	192	192	192
Total Contribution to Peak from Existing (MW)	**8,243**	**7,807**	**6,120**	**5,099**	**5,033**	**4,779**

Supply Resources (Future)	**2020**	**2025**	**2030**	**2035**	**2040**	**2050**
Future Resources Capacity (MW)						
NGCC	-	-	1,135	1,135	1,135	570
NGCT (frame)	-	-	362	724	724	724
Solar	-	700	1,900	3,400	5,525	8,925
Wind	-	462	1,400	2,250	2,400	4,300
Geothermal	-	-	-	-	-	250
Renewable Fuels	-	-	-	-	-	1,448
Storage (4 hours)	-	1,050	1,700	3,600	3,550	3,400
Storage (8 hours)	-	-	-	-	1,250	1,250
Storage (12 hours)	-	-	-	-	200	3,500
Microgrid	-	31	56	131	131	131
Market Purchases	150	-	-	-	-	-
Contribution to Peak - ELCC Adjusted (MW)						
Thermal (Gas, Nuclear)	-	-	1,497	1,859	1,859	1,294
Renewables (Solar, Wind, Geothermal, Biomass, Fuels)	-	372	576	653	599	2,678
Energy Storage	-	694	1,249	2,211	3,184	4,153
Other (Microgrid, Market Purchases)	150	31	56	131	131	131
Total Contribution to Peak from Existing (MW)	**150**	**1,097**	**3,378**	**4,854**	**5,773**	**8,256**

Total Planning Capacity	**2020**	**2025**	**2030**	**2035**	**2040**	**2050**
Total Capacity (MW)	8,393	8,904	9,497	9,953	10,806	13,035

Capacity Position (MW)	26	4	88	13	89	46

Load and Resource Table for Energy Rules 100% portfolio

System Peak Demand	**2020**	**2025**	**2030**	**2035**	**2040**	**2050**
Base Peak Demand (MW)	7,468	8,639	9,950	11,227	12,599	15,890
Electrification - EV & Building (MW)	2	8	23	44	73	128
Energy Efficiency (MW)	(105)	(754)	(1,479)	(2,155)	(2,832)	(4,111)
Distributed Generation (MW)	(4)	(40)	(133)	(206)	(200)	(130)
Demand Response (MW)	(21)	(137)	(224)	(337)	(399)	(574)
Net System Peak (MW)	**7,340**	**7,716**	**8,136**	**8,573**	**9,241**	**11,203**
Planning Reserve Margin (%)	15%	15%	15%	15%	15%	15%
Reserve Requirements (MW)	1,026	1,184	1,274	1,367	1,476	1,786
Total Firm Load Obligation (MW)	**8,366**	**8,900**	**9,410**	**9,940**	**10,717**	**12,989**

Supply Resources (Existing)	**2020**	**2025**	**2030**	**2035**	**2040**	**2050**
Existing Resources Capacity (MW)						
NGCC	2,995	3,489	1,891	1,891	1,891	-
NGCT	1,545	1,545	1,545	1,545	1,545	-
Coal	1,357	970	970	-	-	-
Nuclear	1,146	1,146	1,146	1,146	1,146	1,146
Solar	532	525	517	510	499	195
Wind	284	284	197	197	-	-
Geothermal	10	10	-	-	-	-
Biomass/Biogas	17	3	3	-	-	-
Storage (4 hours)	2	2	2	2	-	-
Microgrid	32	32	32	32	32	32
Market Purchases	685	160	160	160	160	160
Contribution to Peak - ELCC Adjusted (MW)						
Thermal (Gas, Coal, Nuclear)	7,043	7,150	5,552	4,582	4,582	1,146
Renewables (Solar, Wind, Geothermal, Biomass)	485	464	374	324	259	4

Energy Storage	2	1	1	1	-	-
Other (Microgrid, Market Purchases)	717	192	192	192	192	192
Total Contribution to Peak from Existing (MW)	**8,247**	**7,807**	**6,120**	**5,099**	**5,033**	**1,342**

Supply Resources (Future)	**2020**	**2025**	**2030**	**2035**	**2040**	**2050**
Future Resources Capacity (MW)						
NGCC	-	-	1,135	1,135	1,135	-
NGCT (frame)	-	-	362	724	724	-
Solar	-	700	1,900	3,400	6,575	7,375
Wind	-	462	1,400	2,250	2,600	3,300
Geothermal	-	-	-	-	-	250
Renewable Fuels	-	-	-	-	-	4,706
Storage (4 hours)	-	1,050	1,700	3,600	3,550	5,000
Storage (8 hours)	-	-	-	-	1,250	5,000
Storage (12 hours)	-	-	-	-	1,000	3,500
Microgrid	-	31	56	131	131	131
Market Purchases	150	-	-	-	-	-
Contribution to Peak - ELCC Adjusted (MW)						
Thermal (Gas, Nuclear)	-	-	1,497	1,859	1,859	-
Renewables (Solar, Wind, Geothermal, Biomass, Fuels)	-	372	576	653	646	5,712
Energy Storage	-	694	1,249	2,213	3,643	5,830
Other (Microgrid, Market Purchases)	150	31	56	131	131	131
Total Contribution to Peak from Existing (MW)	**150**	**1,097**	**3,378**	**4,857**	**6,280**	**11,673**

Total Planning Capacity	**2020**	**2025**	**2030**	**2035**	**2040**	**2050**
Total Capacity (MW)	8,397	8,904	9,497	9,956	11,313	13,015
Capacity Position (MW)	30	4	88	15	596	26

5.2 TEP LOAD AND RESOURCE TABLES

Below are the load and resource tables developed by TEP and the Ascend team for assessing the costs of the proposed energy rules.

Load and Resource Table for Least Cost portfolio – TEP Assumptions

System Peak Demand	**2020**	**2025**	**2030**	**2035**	**2040**	**2050**
Base Peak Demand (MW)	2,589	2,674	2,881	2,931	3,083	3,370
Electrification - EV & Building (MW)	1	14	48	112	156	214
Energy Efficiency (MW)	(8)	(43)	(69)	(101)	(130)	(189)
Distributed Generation (MW)	(3)	(19)	(29)	(35)	(49)	(69)
Demand Response (MW)	(41)	(43)	(46)	(48)	(51)	(57)
Net System Peak (MW) - Least Cost	**2,538**	**2,584**	**2,785**	**2,859**	**3,009**	**3,269**
Planning Reserve Margin (%)	15%	15%	15%	15%	15%	15%
Reserve Requirements (MW)	381	388	418	429	451	490
Total Firm Load Obligation (MW)	**3,096**	**3,152**	**3,398**	**3,488**	**3,671**	**3,988**

Supply Resources (Existing)	**2020**	**2025**	**2030**	**2035**	**2040**	**2050**
Existing Resources Capacity (MW)						
NGCC	1,093	1,146	1,146	1,146	1,146	1,146
NGCT	212	212	91	91	91	91
Gas Steam	261	260	260	156	-	-
NG RICE	182	182	182	182	182	182
Coal	1,056	903	516	-	-	-
Solar	203	307	298	169	169	169
Wind	80	425	425	375	375	375
Storage (4 hours)		30	30	30	30	30

Supply Resources (Future)	**2020**	**2025**	**2030**	**2035**	**2040**	**2050**
Future Resources Capacity (MW)						
NGCC	-	-	-	-	500	500
NGCT (frame)	-	-	-	-	-	-

NGCT (aero)	-	-	-	-	-	-
NG RICE	-	-	-	-	-	-
Solar	-	125	250	1,500	1,800	1,800
Wind	-	-	200	500	700	700
Geothermal	-	-	-	-	-	-
Biomass/Biogas	-	-	-	-	-	-
Renewable Fuels	-	-	-	-	-	-
Storage (4 hours)	-	150	565	1,415	1,415	1,415
Storage (8 hours)		-	-	-	-	-
Storage (12 hours)	-	-	-	-	-	-

Load and Resource Table for Energy Rules 80% portfolio – TEP Assumptions

System Peak Demand	**2020**	**2025**	**2030**	**2035**	**2040**	**2050**
Base Peak Demand (MW)	2,589	2,674	2,881	2,931	3,083	3,370
Electrification - EV & Building (MW)	1	14	48	112	156	214
Energy Efficiency (MW)	(29)	(111)	(199)	(277)	(365)	(564)
Distributed Generation (MW)	(3)	(19)	(29)	(35)	(49)	(69)
Demand Response (MW)	(41)	(43)	(46)	(48)	(51)	(57)
Net System Peak (MW) - Rules	**2,517**	**2,516**	**2,655**	**2,683**	**2,773**	**2,894**
Planning Reserve Margin (%)	15%	15%	15%	15%	15%	15%
Reserve Requirements (MW)	377	377	398	403	416	434
Total Firm Load Obligation (MW)	**2,894**	**2,894**	**3,053**	**3,086**	**3,189**	**3,328**

Supply Resources (Existing)	**2020**	**2025**	**2030**	**2035**	**2040**	**2050**
Existing Resources Capacity (MW)						
NGCC	1,093	1,146	1,146	1,146	1,146	1,146
NGCT	212	212	91	91	91	91
Gas Steam	261	260	260	156	-	-
NG RICE	182	182	182	182	182	182
Coal	1,056	903	516	-	-	-

Solar	203	307	298	169	169	169
Wind	80	425	425	375	375	375
Storage (4 hours)	-	30	30	30	30	30

Supply Resources (Future)	**2020**	**2025**	**2030**	**2035**	**2040**	**2050**
Future Resources Capacity (MW)						
NGCC	-	-	-	-	-	-
NGCT (frame)	-	-	-	-	-	-
NGCT (aero)	-	-	-	-	-	-
NG RICE	-	-	-	-	-	-
Solar	-	125	250	1,500	2,500	3,000
Wind	-	-	200	500	1,250	1,250
Renewable Fuels	-	-	-	-	-	-
Storage (4 hours)	-	150	565	1,415	1,415	1,415
Storage (8 hours)	-	-	-	-	550	800
Storage (12 hours)	-	-	-	-	-	-

Load and Resource Table for Energy Rules 100% portfolio – TEP Assumptions

System Peak Demand	**2020**	**2025**	**2030**	**2035**	**2040**	**2050**
Base Peak Demand (MW)	2,589	2,674	2,881	2,931	3,083	3,370
Electrification - EV & Building (MW)	1	14	48	112	156	214
Energy Efficiency (MW)	(29)	(111)	(199)	(277)	(365)	(564)
Distributed Generation (MW)	(3)	(19)	(29)	(35)	(49)	(69)
Demand Response (MW)	(41)	(43)	(46)	(48)	(51)	(57)
Net System Peak (MW) - Rules	**2,517**	**2,516**	**2,655**	**2,683**	**2,773**	**2,894**
Planning Reserve Margin (%)	15%	15%	15%	15%	15%	15%
Reserve Requirements (MW)	377	377	398	403	416	434
Total Firm Load Obligation (MW)	**2,894**	**2,894**	**3,053**	**3,086**	**3,189**	**3,328**

Supply Resources (Existing)	**2020**	**2025**	**2030**	**2035**	**2040**	**2050**

Existing Resources Capacity (MW)						
NGCC	1,093	1,146	1,146	1,146	1,146	-
NGCT	212	212	91	91	91	-
Gas Steam	261	260	260	156	156	-
NG RICE	182	182	182	182	182	-
Coal	1,056	903	516	-	-	-
Solar	203	307	298	169	169	169
Wind	80	425	425	375	375	375
Storage (4 hours)	-	30	30	30	30	30

Supply Resources (Future)	2020	2025	2030	2035	2040	2050
Future Resources Capacity (MW)						
NGCC	-	-	-	-	-	-
NGCT (frame)	-	-	-	-	182	-
NGCT (aero)	-	-	-	-	-	-
NG RICE	-	-	-	-	-	-
Solar	-	125	250	1,500	2,500	3,000
Wind	-	-	200	500	1,250	1,250
Renewable Fuels	-	-	-	-	-	1,757
Storage (4 hours)	-	150	565	1,415	1,415	1,415
Storage (8 hours)	-	-	-		550	800
Storage (12 hours)	-	-	-	-	-	-

Load and Resource Table for Least Cost portfolio – Ascend Assumptions

System Peak Demand	2020	2025	2030	2035	2040	2050
Base Peak Demand (MW)	2,589	2,674	2,881	2,931	3,083	3,370
Electrification - EV & Building (MW)	1	14	48	112	156	214
Energy Efficiency (MW)	(8)	(43)	(69)	(101)	(130)	(189)
Distributed Generation (MW)	(3)	(19)	(29)	(35)	(49)	(69)
Demand Response (MW)	(41)	(43)	(46)	(48)	(51)	(57)

Net System Peak (MW)	**2,538**	**2,584**	**2,785**	**2,859**	**3,009**	**3,269**
Planning Reserve Margin (%)	15%	15%	15%	15%	15%	15%
Reserve Requirements (MW)	381	388	418	429	451	490
Total Firm Load Obligation (MW)	**3,096**	**3,152**	**3,398**	**3,488**	**3,671**	**3,988**

Supply Resources (Existing)	**2020**	**2025**	**2030**	**2035**	**2040**	**2050**
Existing Resources Capacity (MW)						
NGCC	1,093	1,146	1,146	1,146	1,100	-
NGCT	212	212	91	91	91	-
Gas Steam	261	260	260	156	-	-
NG RICE	182	182	182	182	182	-
Coal	1,056	903	516	-	-	-
Solar	203	307	298	169	169	169
Wind	80	425	425	375	375	375
Storage (4 hours)		30	30	30	30	-

Supply Resources (Future)	**2020**	**2025**	**2030**	**2035**	**2040**	**2050**
Future Resources Capacity (MW)						
NGCC	-	-	-	-	-	750
NGCT (frame)	-	-	-	-	-	-
NG RICE	-	225	650	950	1,675	2,725
Solar	-	125	250	1,500	2,000	2,750
Wind	-	-	200	500	750	1,250
Renewable Fuels	-	-	-	-	-	-
Storage (4 hours)	-	150	565	1,415	1,500	2,500
Storage (8 hours)	-	-	-	-	-	-
Storage (12 hours)	-	-	-	-	-	-

Load and Resource Table for Energy Rules 80% portfolio – Ascend Assumptions

System Peak Demand	**2020**	**2025**	**2030**	**2035**	**2040**	**2050**
Base Peak Demand (MW)	2,589	2,674	2,881	2,931	3,083	3,370

Electrification - EV & Building (MW)	1	14	48	112	156	214
Energy Efficiency (MW)	(29)	(111)	(199)	(277)	(365)	(564)
Distributed Generation (MW)	(3)	(19)	(29)	(35)	(49)	(69)
Demand Response (MW)	(41)	(43)	(46)	(48)	(51)	(57)
Net System Peak (MW)	**2,517**	**2,516**	**2,655**	**2,683**	**2,773**	**2,894**
Planning Reserve Margin (%)	15%	15%	15%	15%	15%	15%
Reserve Requirements (MW)	377	377	398	403	416	434
Total Firm Load Obligation (MW)	**2,894**	**2,894**	**3,053**	**3,086**	**3,189**	**3,328**

Supply Resources (Existing)	**2020**	**2025**	**2030**	**2035**	**2040**	**2050**
Existing Resources Capacity (MW)						
NGCC	1,093	1,146	1,146	1,146	1,100	-
NGCT	212	212	91	91	91	-
Gas Steam	261	260	260	156	-	-
NG RICE	182	182	182	182	182	182
Coal	1,056	903	516	-	-	-
Solar	203	307	298	169	169	-
Wind	80	425	425	375	375	-
Storage (4 hours)	-	30	30	30	30	-

Supply Resources (Future)	**2020**	**2025**	**2030**	**2035**	**2040**	**2050**
Future Resources Capacity (MW)						
NGCC	-	-	-	-	-	-
NGCT (frame)	-	-	-	-	-	-
NGCT (aero)	-	-	-	-	-	-
NG RICE	-	-	-	-	250	1,790
Solar	-	125	250	1,500	2,000	4,000
Wind	-	-	200	500	1,500	2,500
Renewable Fuels	-	-	-	-	-	-
Storage (4 hours)	-	150	600	1,415	2,000	3,000
Storage (8 hours)	-	-	255	600	1,000	2,000

Storage (12 hours)	-	-	-	-	-	-

Load and Resource Table for Energy Rules 80% portfolio – Ascend Assumptions

System Peak Demand	**2020**	**2025**	**2030**	**2035**	**2040**	**2050**
Base Peak Demand (MW)	2,589	2,674	2,881	2,931	3,083	3,370
Electrification - EV & Building (MW)	1	14	48	112	156	214
Energy Efficiency (MW)	(29)	(111)	(199)	(277)	(365)	(564)
Distributed Generation (MW)	(3)	(19)	(29)	(35)	(49)	(69)
Demand Response (MW)	(41)	(43)	(46)	(48)	(51)	(57)
Net System Peak (MW)	**2,517**	**2,516**	**2,655**	**2,683**	**2,773**	**2,894**
Planning Reserve Margin (%)	15%	15%	15%	15%	15%	15%
Reserve Requirements (MW)	377	377	398	403	416	434
Total Firm Load Obligation (MW)	**2,894**	**2,894**	**3,053**	**3,086**	**3,189**	**3,328**

Supply Resources (Existing)	**2020**	**2025**	**2030**	**2035**	**2040**	**2050**
Existing Resources Capacity (MW)						
NGCC	1,093	1,146	1,146	1,146	1,100	-
NGCT	212	212	91	91	91	-
Gas Steam	261	260	260	156	-	-
NG RICE	182	182	182	182	182	-
Coal	1,056	903	516	-	-	-
Solar	203	307	298	169	169	-
Wind	80	425	425	375	375	-
Storage (4 hours)	-	30	30	30	30	-

Supply Resources (Future)	**2020**	**2025**	**2030**	**2035**	**2040**	**2050**
Future Resources Capacity (MW)						
NGCC	-	-	-	-	-	-
NGCT (frame)	-	-	-	-	-	-
NGCT (aero)	-	-	-	-	-	-

NG RICE	-	-	-	-	-	-
Solar	-	125	250	1,500	2,000	4,000
Wind	-	-	200	500	1,500	2,500
Renewable Fuels	-	-	-	-	-	1,725
Storage (4 hours)	-	150	600	1,415	2,000	3,000
Storage (8 hours)	-	-	255	600	1,000	2,000
Storage (12 hours)	-	-	-	-	250	500

ATTACHMENT

Ascend Analytics

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REVISED

REPORT

ARIZONA UTILITY INTEGRATED RESOURCE PLAN REVIEW

ADDENDUM – UNSE RESULTS

PREPARED FOR:

ARIZONA CORPORATION COMMISSION

SEPTEMBER 21, 2021

Authors:

Ascend Analytics

David Millar, Director of Resource Planning Consulting
Anthony Boukarim, Senior Consultant
Zach Brode, Senior Energy Analyst
Brandon Mauch, Manager, Resource Planning Consulting Analytics
Brent Nelson, Manager, Market Analysis and Forecasting

Verdant Associates

Colin Elliot, Senior Principal Consultant
William Marin, Co-Founder
Jean Shelton, Co-Founder

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Addendum Summary

This report complements the "Arizona Utility Integrated Resource Plan Review" filed on August 13, 2021 in Docket No. E-00000V-19-0034 and August 19, 2021 in Docket No. RU-00000A-18-0284. It includes a summary of the estimated cost impacts on UniSource Energy Services (UNSE) customers from adopting the proposed Energy Rules versus a hypothetical "least-cost" pathway.

RESULTS OF ENERGY RULES VERSUS LEAST COST ANALYSIS

Ascend used the modeling results provided by UNSE to calculate differences in revenue requirements (cost of supply to serve load and incremental transmission revenue requirements), average rate impacts (revenue requirements divided by retail sales), and average monthly residential bill impacts (rate impacts multiplied by average monthly energy consumption). Table AS -1a, b and c show the results of the analysis for UNSE:

AS-1a: Revenue Requirements ($M)

	2025	2030	2035	2040	2050
100% Clean	227 - 242	285 - 295	320 - 340	365 – 417	504 - 533
80% Clean	223 - 239	283 - 292	312 - 339	339 – 410	492 - 515
Least Cost	223 - 231	255 - 258	280 - 282	315 – 322	363 - 398
Difference (100% Clean – Least Cost)	3 - 11	27 - 41	37 - 60	50 - 96	135 - 142
Difference (80% Clean – Least Cost)	0 - 8	25 - 37	30 - 59	24 - 89	117 - 129
% Difference (100% Clean – Least Cost)	2% - 5%	10% - 16%	13% - 21%	16% - 30%	34% - 39%
% Difference (80% Clean – Least Cost)	0% - 4%	10% - 15%	11% - 21%	8% - 28%	29% - 36%

AS-1b: Average Rate Impacts ($/kWh)

	2025	2030	2035	2040	2050
100% Clean	0.115 - 0.123	0.141 - 0.146	0.148 - 0.157	0.170 - 0.195	0.251 - 0.265
80% Clean	0.113 - 0.122	0.140 - 0.145	0.144 - 0.157	0.158 - 0.191	0.245 - 0.256
Least Cost	0.113 - 0.117	0.126 - 0.128	0.129 - 0.130	0.147 - 0.150	0.181 - 0.198
Difference (100% Clean – Least Cost)	0.0018 - 0.0054	0.0132 - 0.0202	0.0171 - 0.0276	0.0231 - 0.0446	0.0674 - 0.0706
Difference (80% Clean – Least Cost)	0.0000 - 0.0043	0.0125 - 0.0184	0.0138 - 0.0272	0.0112 - 0.0414	0.0585 -0.0645
% Difference (100% Clean – Least Cost)	2% - 5%	10% - 16%	13% - 21%	16% - 30%	34% - 39%
% Difference (80% Clean – Least Cost)	0% - 4%	10% - 15%	11% - 21%	8% - 28%	30% - 36%

AS-1c: Average Monthly Residential Bill Impacts ($)

	2025	2030	2035	2040	2050
100% Clean	115.23 - 122.68	141.18 - 146.42	147.58 - 156.97	170.05 - 194.59	251.13 - 265.04
80% Clean	113.49 - 121.61	140.47 - 144.61	144.22 - 156.56	158.15 - 191.32	245.00 - 256.13
Least Cost	113.48 - 117.33	126.23 - 128.02	129.34 - 130.43	146.91 - 149.97	180.55 - 197.66
Difference (100% Clean – Least Cost)	1.75 - 5.36	13.17 - 20.19	17.15 - 27.64	23.14 - 44.63	67.37 - 70.58
Difference (80% Clean – Least Cost)	0.01 - 4.28	12.46 - 18.38	13.79 - 27.22	11.24 - 41.36	58.47 - 64.45
% Difference (100% Clean – Least Cost)	2% - 5%	10% - 16%	13% - 21%	16% - 30%	34% - 39%
% Difference (80% Clean – Least Cost)	0% - 4%	10% - 15%	11% - 21%	8% - 28%	30% - 36%

Assessment of Proposed Energy Rules Cost

1.1 UNSE

1.1.1 APPROACH

To analyze the costs associated with the energy rules, Ascend and UNSE each designed portfolios that had 80% and 100% reductions in carbon emission by 2050 as well as a 'least cost' portfolio. Ascend interpreted 'least-cost' to mean a portfolio buildout using traditional thermal capacity resources, which could then be compared against portfolios with more renewables and storage.

The 80% and 100% reduction portfolios were set up to comply with the draft Energy Rules for both 80% and 100% reductions in carbon emissions by 2050, as well as meeting interim targets of 50% reductions by 2032 for both cases, 65% by 2040 for the 80% case, and 75% by 2040 for the 100% case. After creating the portfolios under both Ascend and UNSE's assumptions on ELCC and market prices, the UNSE resource planning staff used their Aurora production cost model to estimate the costs of each portfolio. The outputs from the production cost modeling were used to estimate the cost of the Energy Rules and their potential impact on customer rates and costs.

1.1.2 INPUTS AND ASSUMPTIONS

Demand Side:

UNSE's IRP served as the foundation for assumptions and analysis, but additional data requests were necessary to fill the gaps. In cases of ambiguity or inconsistency, additional research and professional judgement was used to derive new assumptions. The following is a summary of the demand side assumptions used in the modeling of the energy rules.

UNSE Base Forecast: The forecast of base energy and peak demand comes from UNSE's 2020 IRP. This forecast shows energy increasing from 1,680 GWh in 2020 to 3,288 in 2035, with an average annual growth rate of 4.6%. This is driven in large by the mining sector, where sales are forecasted to grow from 82 GWh in 2023 to 212 GWh in 2024. Peak demand increased from 484 MW in 2020 to 615 MW in 2035, with an average annual growth rate of 1.62%, reflecting that the substantial increase in energy demand for the mining sector is not coincident with the system peak. Both energy and peak demand forecasts were extended to 2050 using linear extrapolation.

UNSE Electrification: As with TEP, the data for electrification consisted exclusively of a forecast of the total energy associated with electric vehicles. The series is similar to TEP's in that the growth rate is very high in the beginning and tapers off later in the forecast horizon. The forecasted energy associated with EVs grows from 2 GWh in 2020 to 211 GWh in 2035, with an average annual growth rate of 40%. These data were forecasted to 2050 using the same approach as TEP, where the 2050 GWh was calculated based on an assumption of 80% of customers having one EV and then backfilling the series based a declining rate of adoption over time. There are reasons why this number might be higher or lower for the UNSE service territory relative to TEP, but without data to support it, there was no reason to alter these assumptions.

UNSE Energy Efficiency: UNSE's response to this IRP review's data request provided the energy efficiency savings for the energy rules scenario. For the least-cost scenario, the IRP provided annual peak demand savings, but these fluctuated over the forecast, both increasing and decreasing over time.

UNSE Demand Response: In both the energy rules and low-cost scenarios, peak demand savings from demand response for UNSE increase from 8.3 MW in 2020 to 27 MW in 2050. This series is based on the 2020 savings from the DSM plan and then UNSE's preferred portfolio, which projects a four percent annual increases in DR capacity after 2021. There are no energy savings associated with DR.

UNSE Distributed Generation: The forecast of distributed generation comes from the IRP, which projects 16 MW of peak demand savings in 2020 increasing to 53 MW in 2035. Assuming peak coincident factor of 0.2, these were converted to energy savings of 28 GWh in 2020 and 36.8 GWh in 2050. Both energy and demand series were projected to 2050 using linear extrapolation to produce savings of 44.6 GWh and 25.5 MW, respectively.

Supply Side

The Ascend and UNSE assumptions on ELCC are very different. Ascend assumes that the ELCC of renewable resources and storage will decline significantly over the next 30 years, particularly for solar generation, whereas UNSE keeps their capacity value constant. The divergence in ELCC assumptions between Ascend and UNSE result in the portfolios designed by Ascend having significantly more nameplate capacity.

Another source of difference between Ascend and UNSE are the market price assumptions. As discussed in Section 3.4.2 of the original report, Ascend forecasts market prices to remain flat in nominal terms over the next 30 years whereas UNSE forecasts market prices to steadily increase.

Achieving the emissions reduction targets in 2040 and 2050 required retrofitting existing NGCT and RICE units to take hydrogen as a fuel. Figure 1 shows the assumed capital cost forecast for converting the gas units, which is based on Ascend's research and discussion with manufacturers on conversion cost targets.

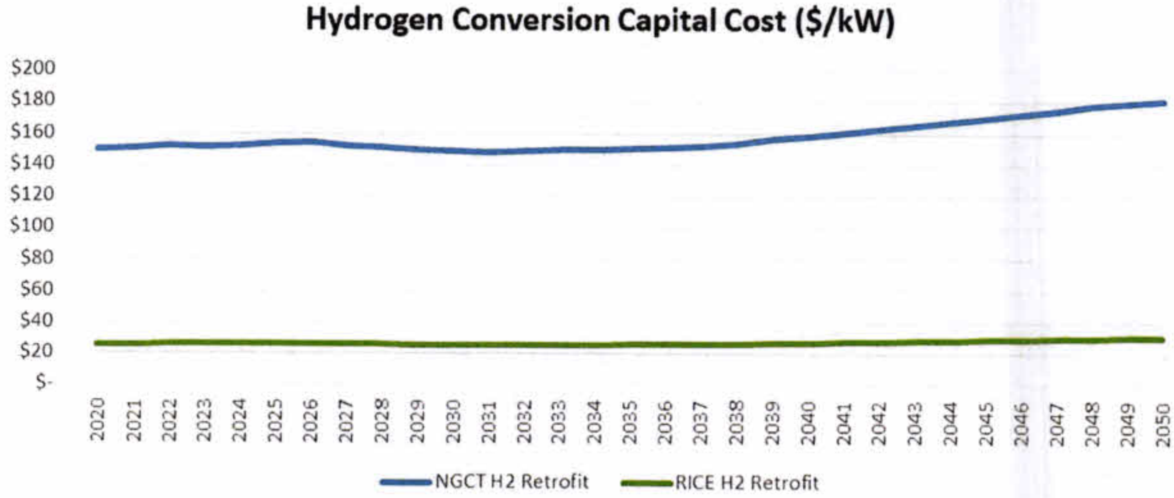

Figure 1: Capital costs of converging gas units to hydrogen

Table 1 below shows the portfolio capacity by resource type. The Energy Rules portfolios rely much more on renewables and energy storage while the least cost portfolio adds a lot of natural gas capacity.

Table 1: UNSE Portfolio Capacity by Resource Type – UNSE Assumptions

	UNSE Least Cost			UNSE Energy Rules 80%			UNSE Energy Rules 100%		
	2030	2040	2050	2030	2040	2050	2030	2040	2050
Natural Gas	383	383	408	383	383	383	383	138	-
Coal	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-	-	-	-
Solar	210	270	370	290	370	590	290	370	590
Wind	60	165	275	245	335	535	250	380	535
Geothermal	-	-	-	-	-	-	-	-	-
Biomass	-	-	-	-	-	-	-	-	-
Storage (4 hours)	60	70	10	60	70	10	60	70	10
Storage (8 hours)	-	-	-	40	100	450	40	100	450
Storage (12 hours)	-	-	-	-	-	-	-	-	-
Microgrid	-	-	-	-	-	-	-	-	-
Market Purchases	-	-	-	-	-	-	-	-	-
Renewable Fuels	-	-	-	-	-	-	-	245	383

Table 2: UNSE Portfolio Capacity by Resource Type – Ascend Assumptions

	Ascend Least Cost			Ascend Energy Rules 80%			Ascend Energy Rules 100%		
	2030	2040	2050	2030	2040	2050	2030	2040	2050
Natural Gas	483	558	608	433	343	150	433	193	-
Coal	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-	-	-	-
Solar	210	320	370	261	370	395	261	370	395
Wind	60	175	250	156	325	350	156	325	350
Geothermal	-	-	-	-	-	-	-	-	-
Biomass	-	-	-	-	-	-	-	-	-
Storage (4 hours)	90	90	90	140	150	150	140	150	150
Storage (8 hours)	-	30	30	-	100	100	-	75	100
Storage (12 hours)	-	-	-	-	-	-	-	-	-
Storage (100 hours)	-	-	-	-	90	200	-	60	200
Microgrid	-	-	-	-	-	-	-	-	-
Market Purchases	-	-	-	-	-	-	-	-	-
Renewable Fuels	-	-	-	-	90	290	-	310	503

1.1.3 RESULTS

The results of the analysis for UNSE are shown in the following tables, with Tables 3-4 showing the revenue requirements for the UNSE and Ascend assumption portfolios respectively, Table 5 showing the net present value (NPV) of the revenue requirements, Tables 6-7 showing the average rate impacts for the UNSE and Ascend assumption portfolios respectively, and Tables 8-9 showing the residential bill impacts for the UNSE and Ascend assumption portfolios respectively.

Table 3: Revenue Requirements ($M) – UNSE Assumptions

	2025	2030	2035	2040	2050
100% Clean Revenue Requirement	227	295	320	365	533
80% Clean Revenue Requirement	223	292	312	339	515
Least Cost Revenue Requirement	223	255	282	315	398
Difference (100% Clean – Least Cost)	3	41	37	50	135
Difference (80% Clean – Least Cost)	0	37	30	24	117
% Difference (100% Clean – Least Cost)	2%	16%	13%	16%	34%
% Difference (80% Clean – Least Cost)	0%	15%	11%	8%	29%

Table 44: Revenue Requirements ($M) – Ascend Assumptions

	2025	2030	2035	2040	2050
100% Clean Revenue Requirement	242	285	340	417	504
80% Clean Revenue Requirement	239	283	339	410	492
Least Cost Revenue Requirement	231	258	280	322	363
Difference (100% Clean – Least Cost)	11	27	60	96	142
Difference (80% Clean – Least Cost)	8	25	59	89	129
% Difference (100% Clean – Least Cost)	5%	10%	21%	30%	39%
% Difference (80% Clean – Least Cost)	4%	10%	21%	28%	36%

Table 55: Revenue Requirement Net Present Value[1] ($M) for 2021 - 2050

	UNSE Assumptions	Ascend Assumptions
100% Clean Revenue Requirement	3,605	3,742
80% Clean Revenue Requirement	3,530	3,711
Least Cost Revenue Requirement	3,328	3,331
Difference (100% Clean – Least Cost)	277	410
Difference (80% Clean – Least Cost)	202	379
% Difference (100% Clean – Least Cost)	8%	12%
% Difference (80% Clean – Least Cost)	6%	11%

[1] *Assumes 7% annual discount rate*

Table 66: Average Rate Impacts ($/kWh) – UNSE Assumptions

	2025	2030	2035	2040	2050
100% Clean Average Rate	0.115	0.146	0.148	0.170	0.265
80% Clean Average Rate	0.113	0.145	0.144	0.158	0.256
Least Cost Average Rate	0.113	0.126	0.130	0.147	0.198
Difference (100% Clean – Least Cost)	0.0018	0.0202	0.0171	0.0231	0.0674
Difference (80% Clean – Least Cost)	0.0000	0.0184	0.0138	0.0112	0.0585
% Difference (100% Clean – Least Cost)	2%	16%	13%	16%	34%
% Difference (80% Clean – Least Cost)	0%	15%	11%	8%	30%

Table 77: Average Rate Impacts ($/kWh) – Ascend Assumptions

	2025	2030	2035	2040	2050
100% Clean Average Rate	0.123	0.141	0.157	0.195	0.251
80% Clean Average Rate	0.122	0.140	0.157	0.191	0.245
Least Cost Average Rate	0.117	0.128	0.129	0.150	0.181
Difference (100% Clean – Least Cost)	0.0054	0.0132	0.0276	0.0446	0.0706
Difference (80% Clean – Least Cost)	0.0043	0.0125	0.0272	0.0414	0.0645
% Difference (100% Clean – Least Cost)	5%	10%	21%	30%	39%
% Difference (80% Clean – Least Cost)	4%	10%	21%	28%	36%

Table 88: Average Monthly Residential Bill Impacts[2] ($) – UNSE Assumptions

	2025	2030	2035	2040	2050
100% Clean Average Monthly Bill	115.23	146.42	147.58	170.05	265.04
80% Clean Average Monthly Bill	113.49	144.61	144.22	158.15	256.13
Least Cost Average Monthly Bill	113.48	126.23	130.43	146.91	197.66
Difference (100% Clean – Least Cost)	1.75	20.19	17.15	23.14	67.37
Difference (80% Clean – Least Cost)	0.01	18.38	13.79	11.24	58.47
% Difference (100% Clean – Least Cost)	2%	16%	13%	16%	34%
% Difference (80% Clean – Least Cost)	0%	15%	11%	8%	30%

[2] Assumes *1,000 kWh monthly consumption per customer*

Table 99: Average Monthly Residential Bill Impacts[3] ($) – Ascend Assumptions

	2025	2030	2035	2040	2050
100% Clean Average Monthly Bill	122.68	141.18	156.97	194.59	251.13
80% Clean Average Monthly Bill	121.61	140.47	156.56	191.32	245.00
Least Cost Average Monthly Bill	117.33	128.02	129.34	149.97	180.55
Difference (100% Clean – Least Cost)	5.36	13.17	27.64	44.63	70.58
Difference (80% Clean – Least Cost)	4.28	12.46	27.22	41.36	64.45
% Difference (100% Clean – Least Cost)	5%	10%	21%	30%	39%
% Difference (80% Clean – Least Cost)	4%	10%	21%	28%	36%

Revenue requirements, shown in Figure 2, are similar in the first 10 years for both Ascend and UNSE assumptions across all three cases. Costs for the 100% and 80% portfolios both rise slightly from the least-cost case beginning in 2030 but remain similar for the Ascend and UNSE assumptions. The low carbon cases deviate more strongly after 2040 as renewable fuels and long-duration storage become necessary to meet the more aggressive emissions targets, with the 2050 revenue requirements similar in both Ascend and UNSE assumptions portfolios. The revenue requirement, and therefore the rate increases, are primarily driven by the capital costs of new resources, with fuel costs becoming less significant as renewable generation increases.

UNSE's is short on capacity by approximately 200 MW out of a 500 MW peak demand and therefore relies heavily on market purchases to meet load. Therefore, meeting interim emissions targets for UNSE requires procuring additional firm capacity while also adding renewables and reducing gas plant capacity factors. As a result, UNSE and Ascend Assumption portfolios see cost increases of 11-21% by 2035. The lower ELCC assumption on renewable resources in the Ascend assumptions results in portfolios with more capacity additions earlier, which in turn results in higher revenue requirements in 2035 and 2040, despite being similar in 2050. Both Ascend and UNSE portfolios expect similar costs associated with the 100% by 2050 case, but the Ascend 'least-cost' portfolio has a lower overall cost, making the 100% by 2050 case a larger incremental cost (39%) than the UNSE case (34%). In either case, these costs are highly uncertain due to unknown future technologies and costs for long-duration storage and renewable fuels. The similarity in costs through mid-term suggests that clean energy targets can be pursued with minimal risk before evaluating the costs of more aggressive targets at a later point when future clean energy costs and technologies are more certain. Cost of new transmission lines is included in the revenue requirement and is assumed to be the same across all six cases, as Figure 3 shows.

[3] Assumes *1,000 kWh monthly consumption per customer*

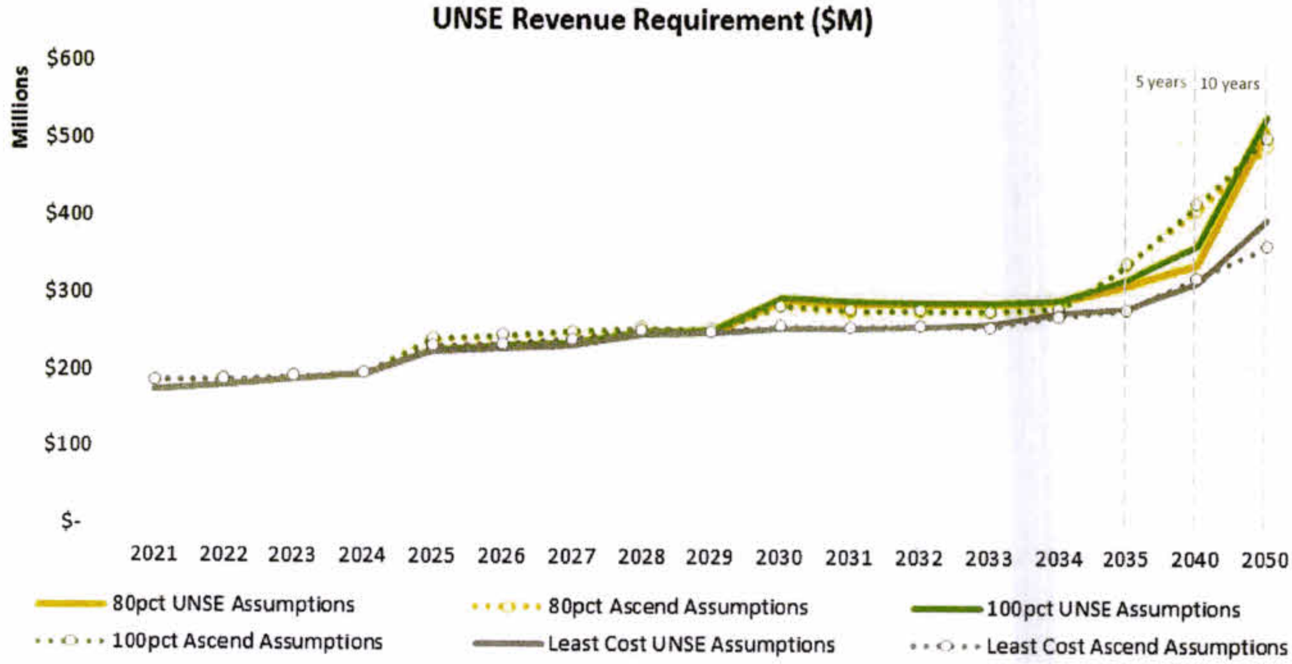

Figure 2: UNSE revenue requirement (including transmission expansions)

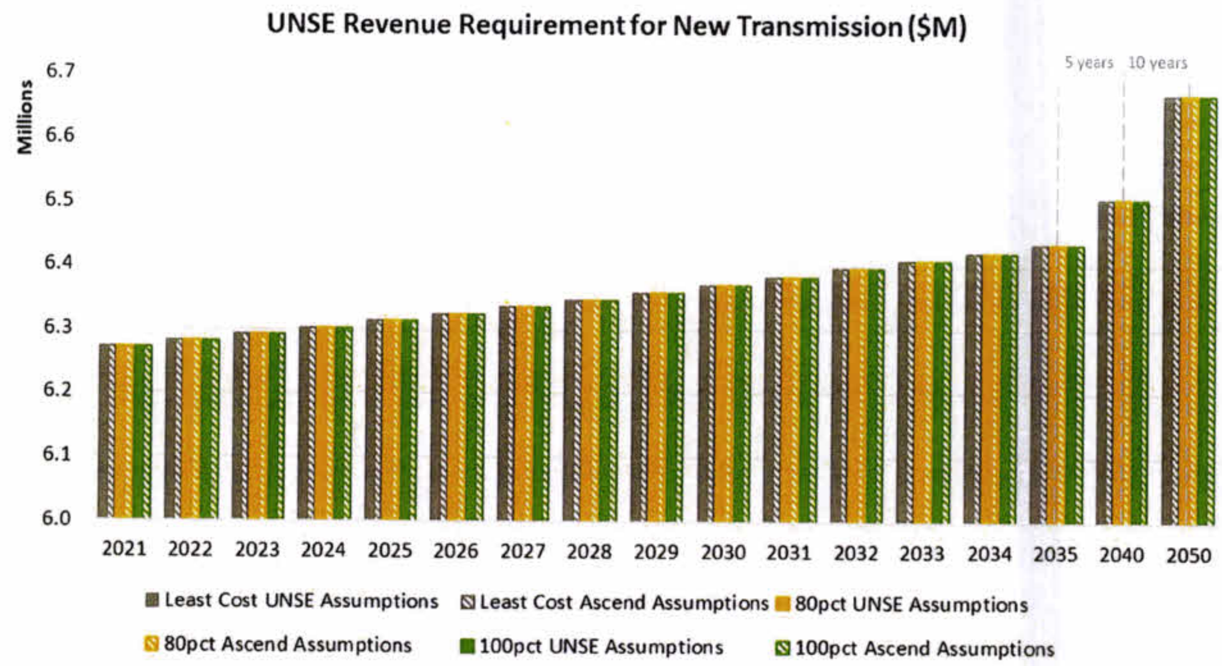

Figure 3: UNSE revenue requirement for new transmission expansions

The "Least Cost" and 80% cases have similar average rates across most of the forecast horizon, before deviating after 2035, as Figure 4 shows. Post 2040, the 80% and 100% cases become significantly more expensive than the least-cost case, although their costs remain similar to each other.

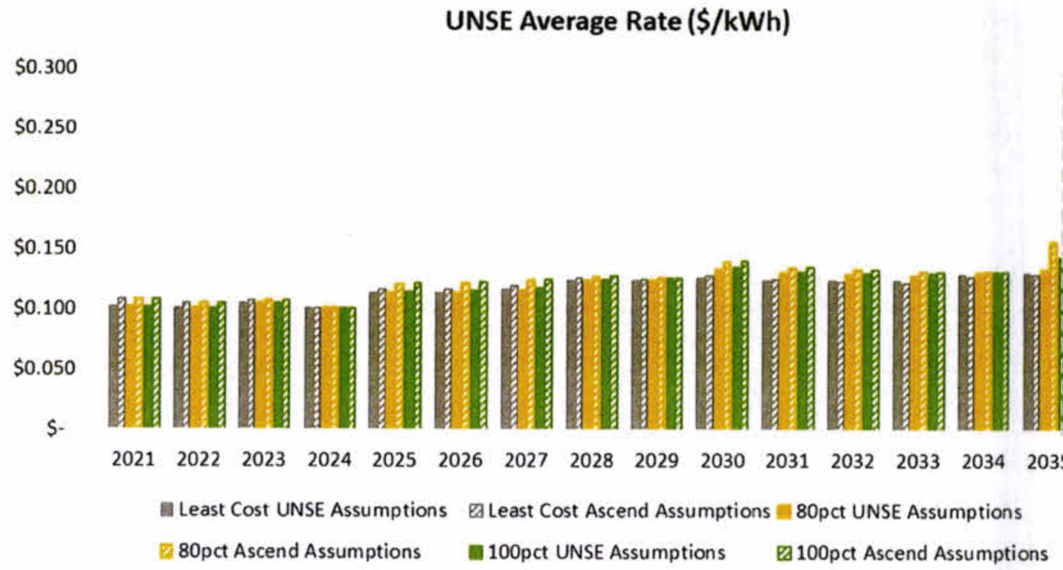

Figure 4: UNSE average electricity rate

Figures 5-8 show the incremental differences in revenue requirements, average rates, and monthly bill of the 80% and 100% clean cases relative to the least-cost case. Both energy rules scenarios have only a modest impact on the average rate and revenue requirement at $0.01-$0.03/kWh (nominal dollars) in 2035, depending on the case and assumptions. The $0.03/kWh difference in 2035 for the Ascend Assumptions 100% case would be close to $0.02/kWh in today's dollars assuming 2.5% inflation.

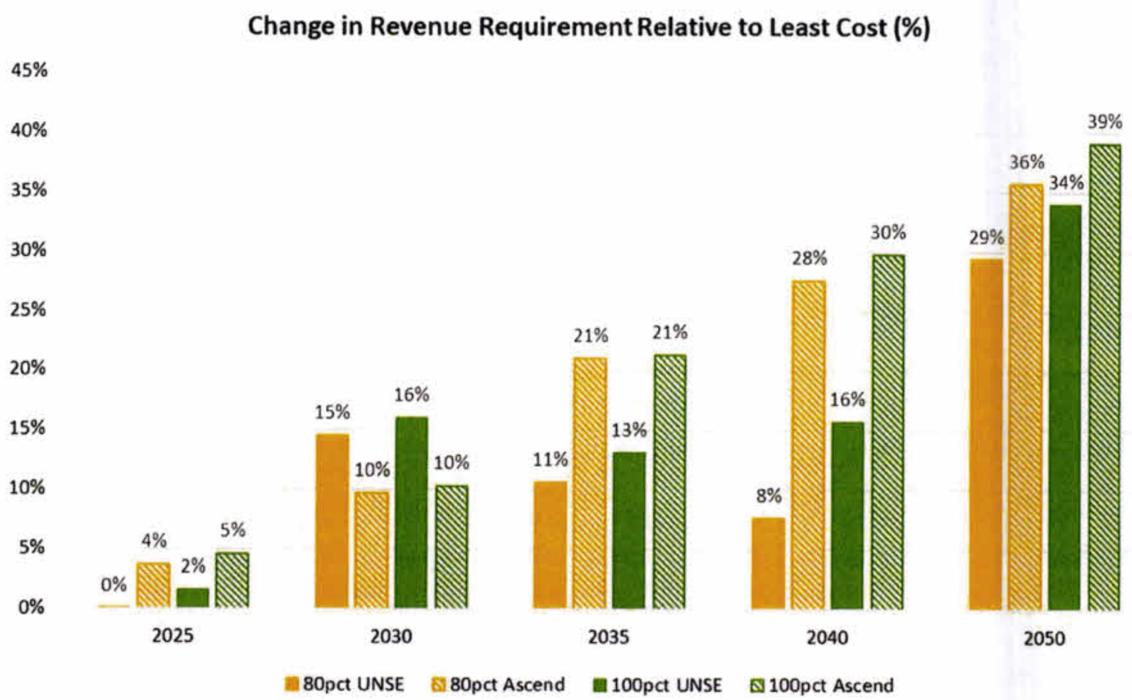

Figure 5: UNSE change in revenue requirement relative to the least cost scenario (percentage)

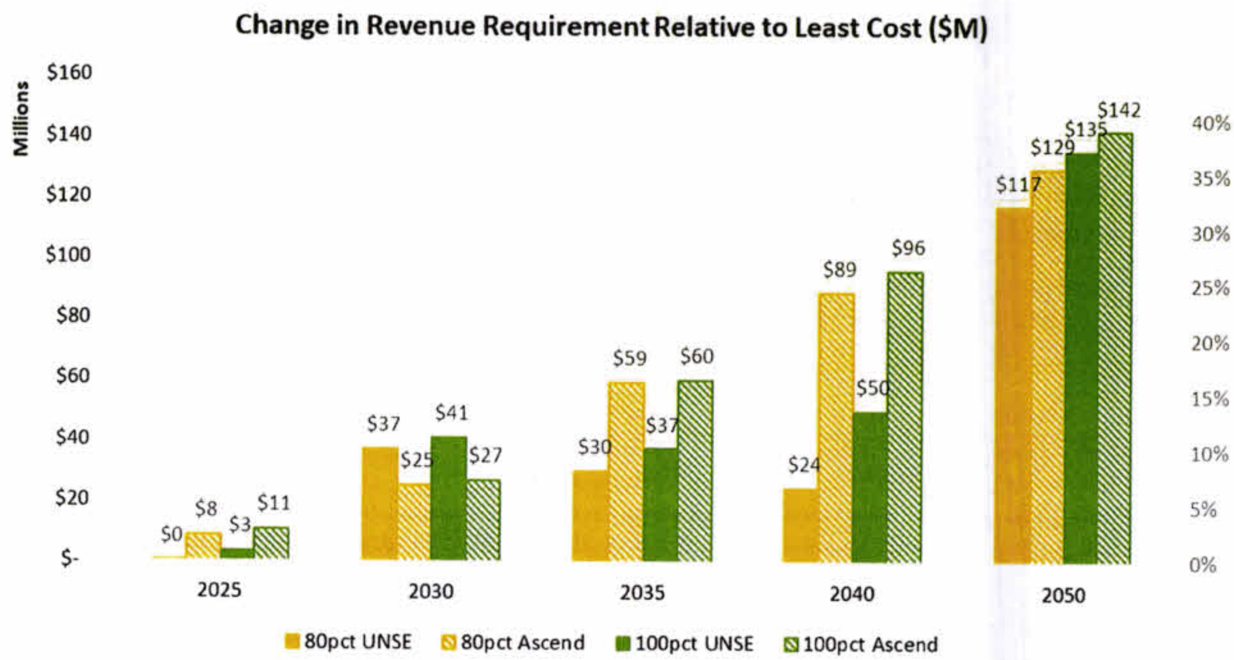

Figure 6: UNSE change in revenue requirement relative to the least cost scenario (nominal dollars)

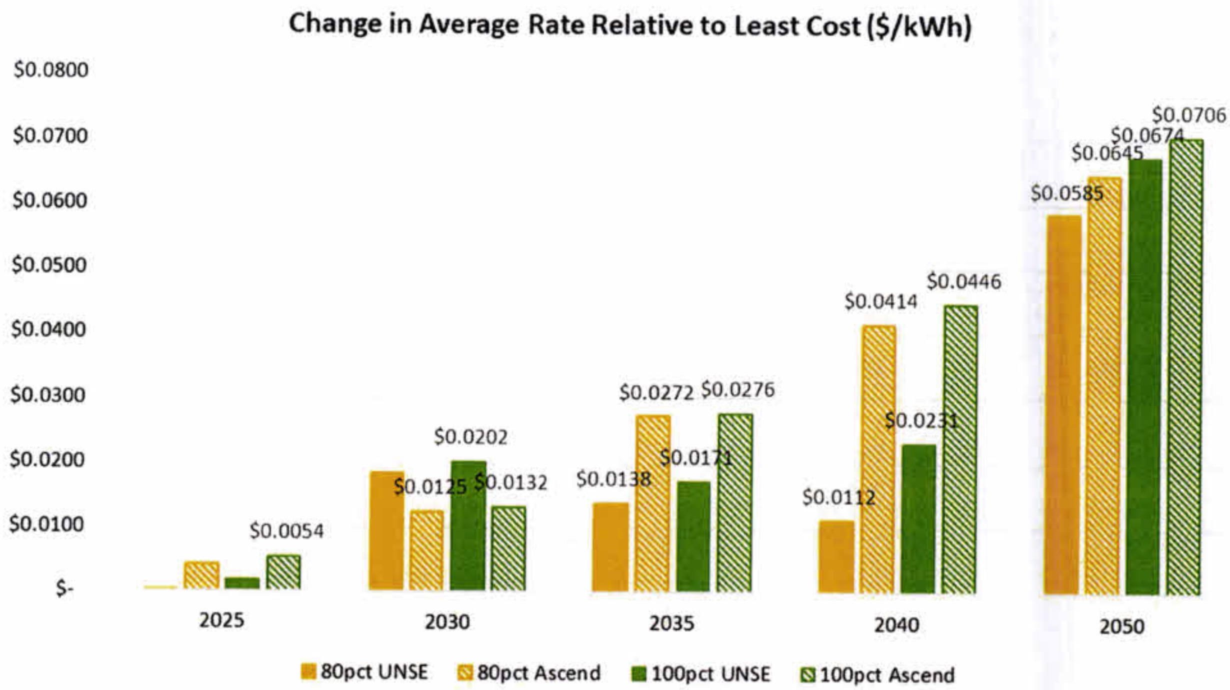

Figure 7: UNSE change in average electricity rate relative to the least cost case

The differences in assumptions used by UNSE and Ascend provide a range of costs for the Energy Rules. The change in customer rates relative to the least cost portfolios is small before 2035, but larger than for TEP due to the challenges associated with reducing emissions from UNSE's portfolio while also adding firm capacity in the near-term. The larger carbon reductions needed after 2035 to meet 80% and 100% reductions drive the average rates up by $0.058/kWh and $0.067/kWh respectively in the Ascend assumptions by 2050, which translates to $0.032-$0.037/kWh in today's dollars. The increase in average rates for the UNSE assumption portfolios is slightly larger, at $0.064/kWh for the 80% case and $0.070/kWh for the 100% case ($0.035-$0.039/kWh in today's dollars). These increased rates would add $60-$70 to the average monthly customer bill ($29-$34 in today's dollars[4]).

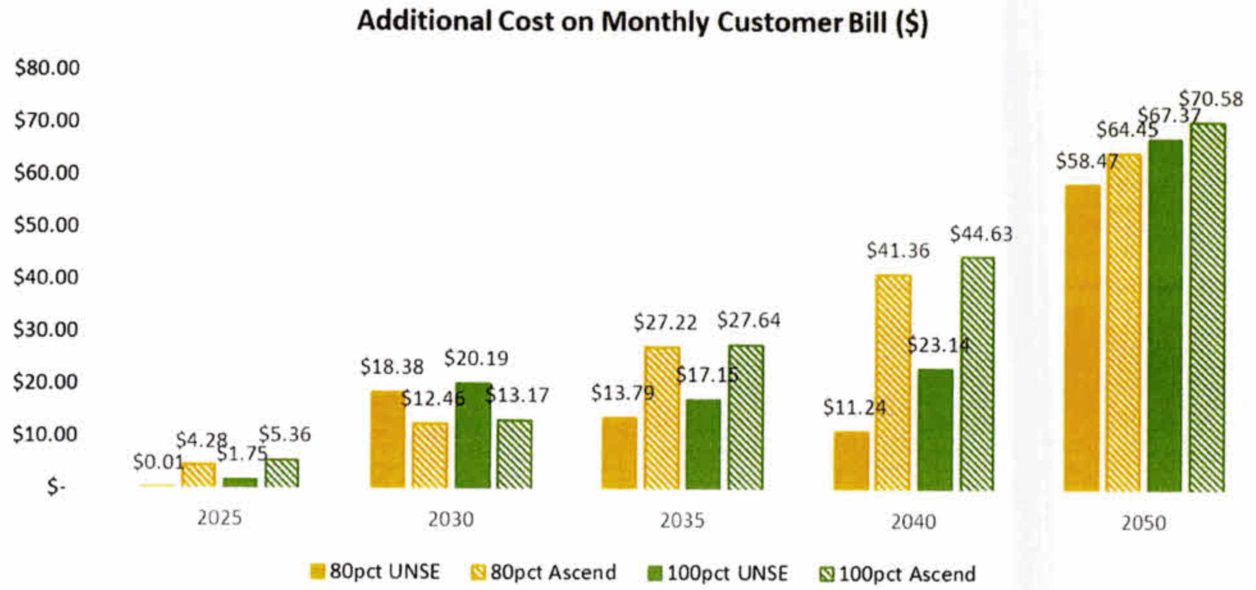

Figure 8: UNSE additional monthly bill impact under 80 and 100% Energy Rules portfolios

The procurement of renewable generation resources and declining capacity factors of gas generation drives the majority of the carbon reductions through the IRP period. The entire gas generation fleet is converted to burn hydrogen in the 100% case for both the Ascend and UNSE assumptions, while in the Ascend Assumptions some gas generation is also converted to burn hydrogen in the 80% case. After 2030, the carbon emissions reductions diverge based on the constraints for each portfolio. The large drop in emissions in 2030 is associated with an assumed 2030 buildout of wind and solar resources. For the 100% reduction case, 2050 market purchases (although minimal) are assumed to have zero carbon intensity, reflecting an expectation of decarbonization in the surrounding states as well in a 100% case.

[4] *Assuming a 2.5% inflation rate*

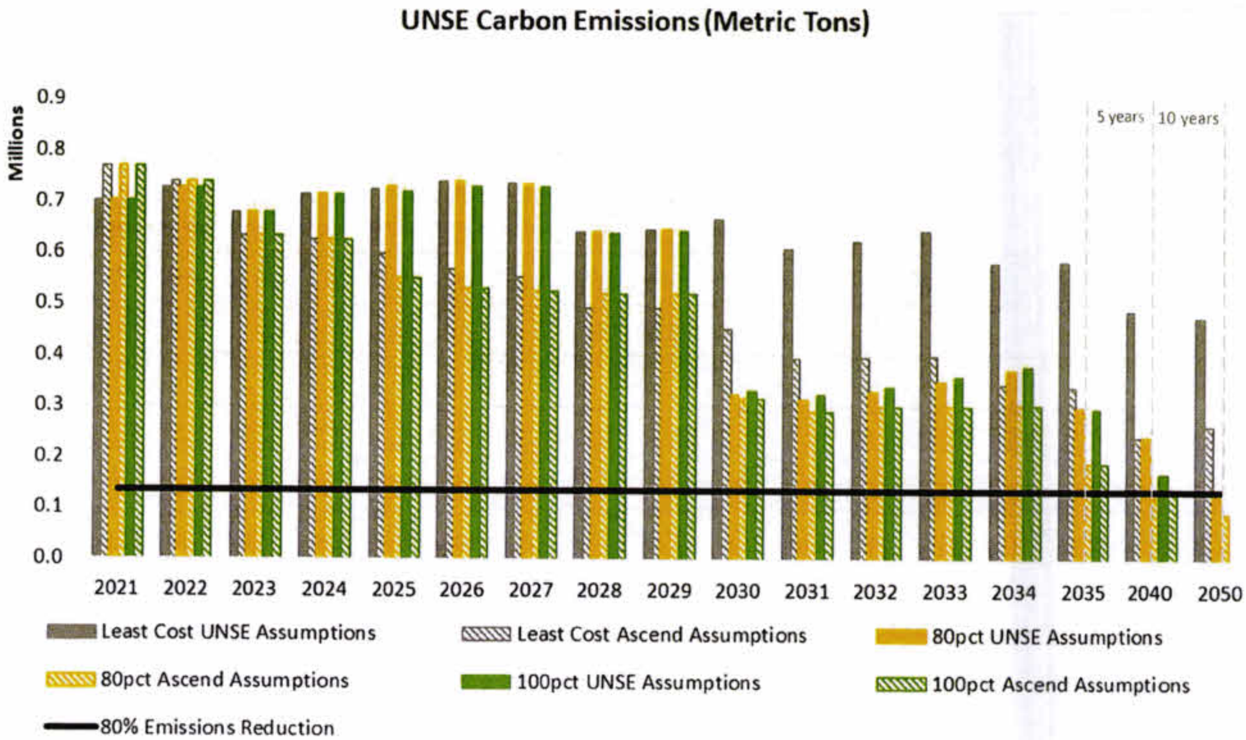

Figure 9: UNSE carbon emissions

While the Energy Rules yield increased costs for UNSE to reach 80% and 100% carbon reductions, with only a small difference between the two, the similarity in costs to the least-cost portfolio through at least 2035 mean that the Energy Rules could be pursued with minimal cost impact until more is known about future costs and technologies. Capital costs are the primary driver of the cost differences post 2035, and these costs are largely speculative today. The paths to both 80% and 100% reductions in carbon emission rely heavily on renewables and storage. The portfolios that were analyzed for UNSE all include the resources necessary to continue decarbonizing the UNSE system.

Appendix

2.1 UNSE LOAD AND RESOURCE TABLES

Below are the load and resource tables developed by UNSE and the Ascend team for assessing the costs of the proposed energy rules.

Load and Resource Table for Least Cost portfolio – UNSE Assumptions

System Peak Demand	**2020**	**2025**	**2030**	**2035**	**2040**	**2050**
Base Peak Demand (MW)	484	541	580	615	666	755
Electrification - EV & Building (MW)	0.2	2.5	8.3	19.3	34.5	54.8
Energy Efficiency (MW)	-9.9	-33.6	-65	-102	-145	-250
Distributed Generation (MW)	-16	-18	-19	-21	-22.4	-25.5
Demand Response (MW)	-8.3	-10.1	-12.3	-15	-18.3	-27
Net System Peak (MW) - Least Cost	**450**	**482**	**492**	**496**	**514**	**507**
Planning Reserve Margin (%)	15%	15%	15%	15%	15%	15%
Reserve Requirements (MW)	70	75	75	75	75	72
Total Firm Load Obligation (MW)	**520**	**556**	**567**	**571**	**590**	**579**

Supply Resources (Existing)	**2020**	**2025**	**2030**	**2035**	**2040**	**2050**
Existing Resources Capacity (MW)						
NGCC	138	138	138	138	138	138
NGCT	55	55	55	55	55	55
Gas Steam	90	90	90	90	90	90
Solar	94	92	90	73	70	70
Wind	10	10	10	-	-	-
Market Purchases	130	-	-	-	-	-

Supply Resources (Future)	2020	2025	2030	2035	2040	2050
Future Resources Capacity (MW)						
NGCC	-	-	-	-	-	-
NGCT (frame)	-	-	-	-	-	-
NGCT (aero)	-	-	-	-	-	-
NG RICE	-	100	100	100	100	125
Solar	-	120	120	150	200	300
Wind	-	-	50	115	165	275
Geothermal	-	-	-	-	-	-
Biomass/Biogas	-	-	-	-	-	-
Renewable Fuels	-	-	-	-	-	-
Storage (4 hours)	-	60	60	70	70	10
Storage (8 hours)	-	-	-	-	-	-
Storage (12 hours)	-	-	-	-	-	-

Load and Resource Table for Energy Rules 80% portfolio – UNSE Assumptions

System Peak Demand	2020	2025	2030	2035	2040	2050
Base Peak Demand (MW)	484	541	580	615	666	755
Electrification - EV & Building (MW)	0.2	2.5	8.3	19.3	34.5	54.8
Energy Efficiency (MW)	-9.9	-33.6	-65	-102	-145	-250
Distributed Generation (MW)	-16	-18	-19	-21	-22.4	-25.5
Demand Response (MW)	-8.3	-10.1	-12.3	-15	-18.3	-27
Net System Peak (MW) - Rules	**450**	**482**	**492**	**496**	**514**	**507**
Planning Reserve Margin (%)	15%	15%	15%	15%	15%	15%
Reserve Requirements (MW)	70	75	75	75	75	72
Total Firm Load Obligation (MW)	**520**	**556**	**567**	**571**	**590**	**579**

Supply Resources (Existing)	2020	2025	2030	2035	2040	2050
Existing Resources Capacity (MW)						
NGCC	138	138	138	138	138	138

NGCT	55	55	55	55	55	55
Gas Steam	90	90	90	90	90	90
Solar	94	92	90	73	70	70
Wind	10	10	10	-	-	-
Market Purchases	130	-	-	-	-	-

Supply Resources (Future)	2020	2025	2030	2035	2040	2050
Future Resources Capacity (MW)						
NGCC	-	-	-	-	-	-
NGCT (frame)	-	-	-	-	-	-
NGCT (aero)	-	-	-	-	-	-
NG RICE	-	100	100	100	100	100
Solar	-	120	200	250	300	520
Wind	-	-	235	285	335	535
Renewable Fuels	-	-	-	-	-	-
Storage (4 hours)	-	60	60	70	70	10
Storage (8 hours)	-	-	40	70	100	450
Storage (12 hours)	-	-	-	-	-	-

Load and Resource Table for Energy Rules 100% portfolio – UNSE Assumptions

System Peak Demand	2020	2025	2030	2035	2040	2050
Base Peak Demand (MW)	484	541	580	615	666	755
Electrification - EV & Building (MW)	0.2	2.5	8.3	19.3	34.5	54.8
Energy Efficiency (MW)	-9.9	-33.6	-65	-102	-145	-250
Distributed Generation (MW)	-16	-18	-19	-21	-22.4	-25.5
Demand Response (MW)	-8.3	-10.1	-12.3	-15	-18.3	-27
Net System Peak (MW) - Rules	**450**	**482**	**492**	**496**	**514**	**507**
Planning Reserve Margin (%)	15%	15%	15%	15%	15%	15%
Reserve Requirements (MW)	70	75	75	75	75	72
Total Firm Load Obligation (MW)	**520**	**556**	**567**	**571**	**590**	**579**

Supply Resources (Existing)	2020	2025	2030	2035	2040	2050
Existing Resources Capacity (MW)						
NGCC	138	138	138	138	138	-
NGCT	55	55	55	55	-	-
Gas Steam	90	90	90	90	-	-
Solar	94	92	90	73	70	70
Wind	10	10	10	-	-	-
Market Purchases	130	-	-	-	-	-

Supply Resources (Future)	2020	2025	2030	2035	2040	2050
Future Resources Capacity (MW)						
NGCC	-	-	-	-	-	-
NGCT (frame)	-	100	100	100	-	-
NGCT (aero)	-	-	-	-	-	-
NG RICE	-	-	-	-	-	-
Solar	-	120	200	250	300	520
Wind	-	-	240	310	380	535
Renewable Fuels	-	-	-	-	245	383
Storage (4 hours)	-	60	60	70	70	10
Storage (8 hours)	-	-	40	70	100	450
Storage (12 hours)	-	-	-	-	-	-

Load and Resource Table for Least Cost portfolio – Ascend Assumptions

System Peak Demand	2020	2025	2030	2035	2040	2050
Base Peak Demand (MW)	484	541	580	615	666	755
Electrification - EV & Building (MW)	0.2	2.5	8.3	19.3	34.5	54.8
Energy Efficiency (MW)	-9.9	-33.6	-65	-102	-145	-250
Distributed Generation (MW)	-16	-18	-19	-21	-22.4	-25.5
Demand Response (MW)	-8.3	-10.1	-12.3	-15	-18.3	-27

Net System Peak (MW)	**450**	**482**	**492**	**496**	**514**	**507**
Planning Reserve Margin (%)	15%	15%	15%	15%	15%	15%
Reserve Requirements (MW)	70	75	75	75	75	72
Total Firm Load Obligation (MW)	**520**	**556**	**567**	**571**	**590**	**579**

Supply Resources (Existing)	**2020**	**2025**	**2030**	**2035**	**2040**	**2050**
Existing Resources Capacity (MW)						
NGCC	138	138	138	138	138	138
NGCT	55	55	55	55	55	55
Gas Steam	90	90	90	90	90	90
NG RICE	-	-	-	-	-	-
Coal	-	-	-	-	-	-
Solar	94	92	90	73	70	70
Wind	10	10	10	-	-	-
Market Purchases	130	-	-	-	-	-

Supply Resources (Future)	**2020**	**2025**	**2030**	**2035**	**2040**	**2050**
Future Resources Capacity (MW)						
NGCC	-	-	-	-	-	-
NGCT (frame)	-	100	100	100	100	150
NG RICE	-	100	100	130	175	175
Solar	-	120	120	150	250	300
Wind	-	-	50	115	175	250
Renewable Fuels	-	-	-	-	-	-
Storage (4 hours)	-	60	90	90	90	90
Storage (8 hours)	-	-	-	-	30	30
Storage (12 hours)	-	-	-	-	-	-

Load and Resource Table for Energy Rules 80% portfolio – Ascend Assumptions

System Peak Demand	**2020**	**2025**	**2030**	**2035**	**2040**	**2050**
Base Peak Demand (MW)	484	541	580	615	666	755

Electrification - EV & Building (MW)	0	3	8	19	35	55
Energy Efficiency (MW)	(44)	(42)	(55)	(53)	(69)	(84)
Distributed Generation (MW)	(16)	(18)	(19)	(21)	(22)	(26)
Demand Response (MW)	(8)	(10)	(12)	(15)	(18)	(27)
Net System Peak (MW)	**416**	**473**	**502**	**545**	**591**	**673**
Planning Reserve Margin (%)	15%	15%	15%	15%	15%	15%
Reserve Requirements (MW)	62	71	75	82	89	101
Total Firm Load Obligation (MW)	**478**	**544**	**577**	**627**	**679**	**774**

Supply Resources (Existing)	**2020**	**2025**	**2030**	**2035**	**2040**	**2050**
Existing Resources Capacity (MW)						
NGCC	138	138	138	138	138	-
NGCT	55	55	55	55	55	-
Gas Steam	90	90	90	-	-	-
NG RICE	-	-	-	-	-	-
Coal	-	-	-	-	-	-
Solar	94	92	90	73	70	70
Wind	10	10	10	-	-	-
Market Purchases	130	-	-	-	-	-

Supply Resources (Future)	**2020**	**2025**	**2030**	**2035**	**2040**	**2050**
Future Resources Capacity (MW)						
NGCC	-	-	-	-	-	-
NGCT (frame)	-	-	-	-	-	-
NGCT (aero)	-	-	-	-	-	-
NG RICE	-	150	150	150	150	150
Solar	-	92	171	250	300	325
Wind	-	42	146	250	325	350
Renewable Fuels	-	-	-	90	90	290
Storage (4 hours)	-	100	140	180	150	150
Storage (8 hours)	-	-	-	60	100	100

Storage (100 hours)	-	-	-	-	90	200

Load and Resource Table for Energy Rules 100% portfolio – Ascend Assumptions

System Peak Demand	**2020**	**2025**	**2030**	**2035**	**2040**	**2050**
Base Peak Demand (MW)	484	541	580	615	666	755
Electrification - EV & Building (MW)	0	3	8	19	35	55
Energy Efficiency (MW)	(44)	(42)	(55)	(53)	(69)	(84)
Distributed Generation (MW)	(16)	(18)	(19)	(21)	(22)	(26)
Demand Response (MW)	(8)	(10)	(12)	(15)	(18)	(27)
Net System Peak (MW)	**416**	**473**	**502**	**545**	**591**	**673**
Planning Reserve Margin (%)	15%	15%	15%	15%	15%	15%
Reserve Requirements (MW)	62	71	75	82	89	101
Total Firm Load Obligation (MW)	**478**	**544**	**577**	**627**	**679**	**774**

Supply Resources (Existing)	**2020**	**2025**	**2030**	**2035**	**2040**	**2050**
Existing Resources Capacity (MW)						
NGCC	138	138	138	138	138	-
NGCT	55	55	55	55	55	-
Gas Steam	90	90	90	-	-	-
NG RICE	-	-	-	-	-	-
Coal	-	-	-	-	-	-
Solar	94	92	90	73	70	70
Wind	10	10	10	-	-	-
Market Purchases	130	-	-	-	-	-

Supply Resources (Future)	**2020**	**2025**	**2030**	**2035**	**2040**	**2050**
Future Resources Capacity (MW)						
NGCC	-	-	-	-	-	-
NGCT (frame)	-	-	-	-	-	-
NGCT (aero)	-	-	-	-	-	-

NG RICE	-	150	150	150	-	-
Solar	-	92	171	250	300	325
Wind	-	42	146	250	325	350
Renewable Fuels	-	-	-	90	310	503
Storage (4 hours)	-	100	140	180	150	150
Storage (8 hours)	-	-	-	60	75	100
Storage (100 hours)	-	-	-	-	60	200